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COAL GASIFICATION SYSTEMS
ENGINEERING AND ANALYSIS
FINAL REPORT
APPENDIX B: MEDIUM BTU GAS DESIGN

December 31, 1980

BDM/H-80-800-TR

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APPENDIX B

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APPENDIX B
INTRODUCTION AND OVERVIEW

This appendix is a compilation of reports presenting the technical results of conceptual design work based on five coal gasification technologies and an analysis of schedule requirements for projects based on these technologies. Cost analyses for these designs are contained in Appendix D.

1. Appendix B-1

   This is a reference facility design report based on the Koppers-Totzek coal gasification process.

2. Appendix B-2

   This is a reference facility design report based on the Texaco coal gasification process.

3. Appendix B-3

   This is a reference facility design report based on the Babcock and Wilcox coal gasification process.

4. Appendix B-4

   This contains facility definition level design reports based on the Lurgi and BGC/Lurgi processes.

5. Appendix B-5

   This presents the results of the schedule analysis.

APPENDIX B-1

KOPPERS-TOTZEK COAL GASIFICATION PLANT REFERENCE FACILITY DESIGN

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1.0 INTRODUCTION

The United States, after a number of years of development based on plentiful and inexpensive oil and natural gas, is entering a period of time when it is essential to supplement these energy sources by the increased use of coal. Coal is the nation's most plentiful fossil fuel. Coal gasification is a means of accomplishing this. While utilization of coal through conversion to gaseous products is not new there is no industry within the US which might serve as a base for establishing cost, operational reliability and requirements, and design data for the large scale environmentally acceptable plants needed.

The Tennessee Valley Authority with systems engineering and analysis support from the George C. Marshall Space Flight Center has initiated a project which would establish the commercial base and demonstrate the requirements for gasifying coal in a large integrated facility. The project consists of gasifying 20,000 tons per day of Eastern coal in a four module plant-the construction of which is staggered to accommodate efficient use of construction manpower and product market development.

The purpose of this study is the systematic engineering and cost analysis of five selected gasifier technologies and the other associated systems required to produce medium BTU gas for delivery into a 600 psig distribution system in Northern Alabama. This effort in a series of design studies provides a reference basis for selection of the final plant configuration and choice of process technologies.

The methodology consists of selection of a systematic breakdown of the facility for purpose of study, identification of available technologies for each system, development of a definition level design and cost analysis for each system, conducting a series of trade studies using the definition design as a basis, and finally development of reference facility designs and cost analyses based on the previous work.

This report covers the work done in establishing a Reference Facility Design based on Koppers-Totzek coal gasification technology. It is one of three such designs, the other two being based on Babcock and Wilcox and Texaco coal gasification processes. The design covers a complete grass roots facility site at Murphy Hill, Alabama. The plant inputs are coal, water and electricity. The plant outputs are medium BTU gas (MBG) and solidified sulfur.

The design approach involved breaking each of four identical modules into process and support systems followed by analysis of each system through identification of available technologies and use of the comparative trade studies to select the preferred processes for each system.

2.0 SUMMARY

A four module, 20,000 TPD, based on KT coal gasification technology has been designed. The plant processes Kentucky No. 9 coal with provisions for up to five percent North Alabama coal. Coal transportation is by river barge except for the Alabama coal which is trucked to the site. Medium BTU gas with heat content of 305 BTU/SCF and not more than 200 ppm sulfur is the primary plant product. Sulfur is recovered for sale as prilled sulfur. Ash disposal is on site. The plant is designed for zero water discharge. Trade studies provided the basis for not using boiler produced steam to drive prime movers. Thus process derived steam in excess of process requirements is superheated for power use in prime movers. Electricity from the TVA grid is used to supply the balance of the plant prime mover power requirements. A study of the effect of mine-mouth coal cleaning showed that coal cleaning is not an economically preferred route.

The plant design was arrived at by a systematic procedure based on published design work, process trade studies, team engineering experience, a NASA provided module level definition of some twenty systems, and the TVA document, "Design Criteria for Conceptual Designs and Assessments of TVA's Coal Gasification Demonstration Plant," March, 1980.

The overall plant configuration is shown schematically in Figure 2.1. As shown, General Facilities, Instrumentation and Control, and Coal Handling serve plant wide functions. All other plant components are contained in four identical process modules. The Instrumentation and Control System operates to monitor overall plant performance and to control intermodule relationships. The total list of systems is given in Table 2.1.

The design procedure involved defining available processes to meet the requirements of each system, technical/economic trade studies to select the preferred processes, and engineering design and flow sheet development for each module. Cost studies assumed a staggered construction schedule for the four modules beginning spring 1981 and a 90 percent on stream factor.

The basis and results of the design study are given in Tables 2.2 and 2.3.

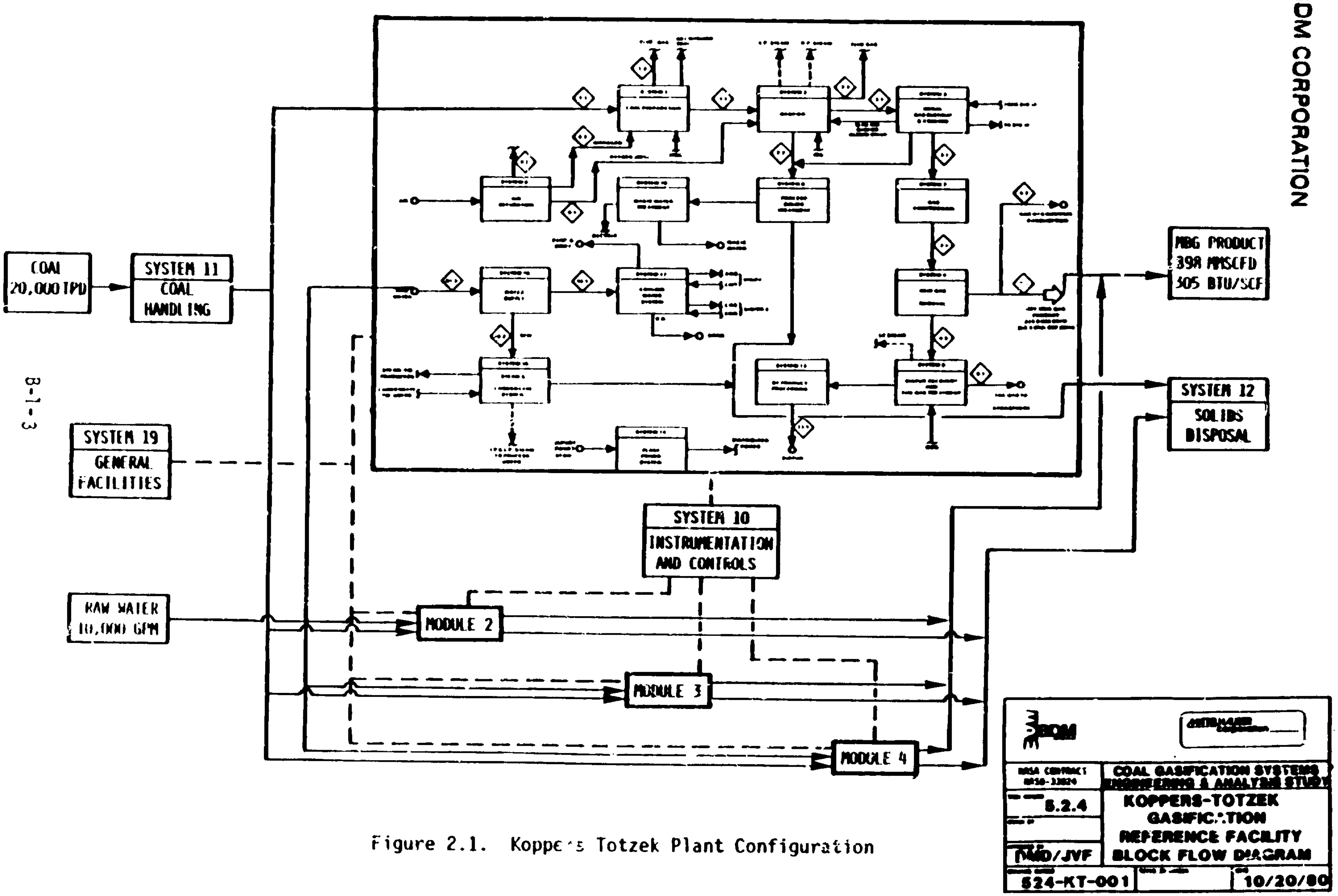

Figure 2.1. Koppers Totzek Plant Configuration

TABLE 2.1. LIST OF SYSTEMS

SYSTEM NO.	NUMBER OF PER MODULE	COST UNITS PER FACILITY	SYSTEM DESCRIPTION
1	1	4	COAL PREPARATION AND FEEDING
2	9	36	GASIFICATION
3	9	36	INITIAL GAS CLEANUP AND COOLING
4	1	4	ACID GAS REMOVAL
5	1	5	SULFUR RECOVERY
6	2	8	AIR SEPARATION
7	1	4	COMPRESSION
8	1	4	PROCESS SOLIDS TREATMENT
10	0	1	INSTRUMENTATION AND CONTROL
11	0	1	COAL HANDLING
12	0	1	SOLIDS DISPOSAL
13	1	4	BY-PRODUCT PROCESSING
14	1	4	PLANT POWER SYSTEM
15	1	4	STEAM GENERATION/DISTRIBUTION
16	1	4	RAW WATER MAKE-UP
17	1	4	COOLING WATER SYSTEM
18	1	4	WASTE WATER TREATMENT
19	0	1	GENERAL FACILITIES

TABLE 2.2. DESIGN BASIS SUMMARY*

PLANT CAPACITY	20,000 TPD
PLANT TYPE	FOUR INDEPENDENT MODULES
COAL TYPE	KENTUCKY NO. 9
PLANT SERVICE FACTOR	90 PER CENT
PLANT LIFE	20 YEARS EACH MODULE
ELECTRICITY SOURCE	TVA GRID-4.16KV, 6.9KV, 13.8KV
WATER	TENNESSEE RIVER
COAL RECEIPT	BARGE +5% BY TRUCK
PRODUCT DELIVERY	MBG AT 600 PSIG
PRODUCT QUALITY	MINIMUM 285 Btu/SCF
SULFUR	PRILLED
COAL COST (1980)	$1.25/MM Btu
LAND COST (1980)	$3,000/ACRE
CLEARING AND GRUBBING (1980)	$2,000/ACRE
ELECTRICITY COSTS (1980)	
BY-PRODUCT CREDIT	NONE
ESCALATION	AS PER TVA SPECIFICATION

*Design Criteria for Conceptual Designs and Assessments of TVA's Coal Gasification Demonstration Plant," Tennessee Valley Authority, March, 1980

TABLE 2.3. DESIGN STUDY RESULTS*

FEED COAL	6,570,000 TPY
WATER	10,000 GPM
PURCHASED ELECTRICITY	3,347 MM KWHY
MBG PRODUCT	898 M MSCFD
MBG PRODUCT	295 MM MSCFY
MBG QUALITY	305 BTU/SCF
SULFUR PRODUCT (PRILLED)	673 LTPD
SULFUR PRODUCT	222,000 LTPY
TOTAL CAPITAL REQUIREMENTS	$2,371 MM
OPERATING AND MAINTENANCE COSTS	$138 MM/YR
COAL, CATALYST, CHEMICALS	$181 MM/YR
PLANT OPERATING STAFF	344 PERSONS
MAINTENANCE/YEAR	$65 MM

* COSTS ARE IN 1980 DOLLARS

Designs in this study were based on published works, engineering experience and judgments, and consultations with appropriate process and equipment vendors followed by design calculations, flow process sheet development and documentation.

Cost estimates are based on normal conceptual level design estimating procedures as described in the "Coal Estimation and Economic Evaluation Methodology," BDM/W-80-258-TR-RV2, submitted as another part of this project work scope and reprinted as Appendix E. Schedule estimates are in accordance with overall guidelines furnished by NASA.

Details of the schedule are considered typical for projects of this type and while they do not represent a detailed analysis specific to this project they represent the complexity and illustrate schedule constraints associated with the subject project. Process flow diagrams are included for the main process systems, air separation system, cooling water system, and steam distribution system as aids in following written system descriptions.

Technical results of the study are reported in this appendix. A cost analysis is included as a part of Appendix D.

3.0 OVERALL FACILITY DESCRIPTION

This section presents and discusses the process design of a plant designed to gasify 20,000 tons per day of coal in four 5000 TPD modules and to produce a medium-Btu product fuel gas (MBG) with a nigher heating value of 305 Btu/SCF. The plant design is based upon using entrained flow of gasifiers as offered by Koppers-Totzek, and upon the design criteria (coal characteristics, product specifications, site data, etc.) set forth by the Tennessee Valley Authority in March, 1980.

3.1 Overall Plant Processing

The overall plant configuration is shown in the block flow diagram, (see Figure 2.1). Kentucky No. 9 coal is received by barge and either placed in a dead storage pile or processed in System 11, Coal Handling. Provisions have also been made to receive up to five per cent of plant capacity by truck. Dead storage provides for 90 days of supply in interruption.

Coal, either directly from barges or from dead storage, is processed in a Bradford breaker and conveyed to four process modules of 5000 TPD capacity each.

In each module, the raw coal fed to the plant from System 11 is crushed and dried in System 1 and fed to System 2, the Koppers-Totzek gasifiers. The feed coal is partially combusted (within the gasifier), with oxygen supplied from the air separation plant, to form a raw product gas which is rich in carbon monoxide and hydrogen. Roughly half of the coal ash is entrained with the gas. The remainder drains by gravity from the gasifier. The raw gas leaves the gasifiers passes through ash quenching and slag recovery and is then cooled to 350^{o}F in waste heat recovery boilers. Heat recovered in the waste heat boilers and from the gasifiers is used to generate steam for the plant. The gas is then further cooled to 100^{o}F in Venturi scrubbers and water wash towers to remove residual char and ash particulates, in System 3, Initial Gas Cleanup and Cooling System.

The raw gas leaves the Venturi scrubbers at 100^{o}F at slightly above atmospheric pressure. It is then compressed in System 7 to about 640-650 psia and sent to System 4, the Acid Gas Removal, where essentially all of the hydrogen sulfide and carbonyl sulfide, and about 45 per cent of the carbon dioxide contained in the raw gas is removed. The acid gas removal system uses the Selexol process (licensed by the Allied Chemical Corporation) in which a physical solvent (the dimethyl ether of polyethylene glycol) absorbs and removes hydrogen sulfide, carbonyl sulfide and the concomitant carbon dioxide from the raw gas.

The acid gas (hydrogen sulfide, carbonyl sulfide and carbon dioxide) is recovered from the Selexol solvent and processed in System 5, Sulfur Recovery and Tail Gas Treatment, wherein over 99 per cent of the hydrogen sulfide and carbonyl sulfide is converted into 668 long tons/day of by-product elemental sulfur. The sulfur recovery unit utilizes the conventional Claus process to convert about 90 to 95 per cent of the hydrogen sulfide (and some of the carbonyl sulfide) in the acid gas into by-product sulfur. The residual tail gas from the Claus unit is then processed in a Beavon-Stretford unit to recover additional by-product sulfur.

Oxygen utilized for the partial combustion of coal and recycle char in the gasifiers is produced in System 6, a conventional air separation plant. Atmospheric air is compressed to about 100 psia, cooled to 100^{o}F and then separated cryogenically into oxygen and nitrogen at about 2 psig. The oxygen is compressed to about 22 psia for use in the gasifiers. A small portion of the nitrogen is also compressed for use in transporting pulverized coal.

In addition to the systems contained in each module and described in Section 4, the plant consists of System 10, the overall plant monitoring and control system; System 11, the coal handling and storage system serving all four modules; and System 12, the solid waste disposal system serving the total facility.

The purpose of System 10 is to provide operational monitoring and supervisory master control of module operations. The system includes instrumentation to measure key characteristics of all major streams (mass, temperature, pressure, composition, density, and/or others as appropriate) and to display these characteristics in a central location. A dedicated computer is provided to record data of interest at the facility management level. Telecommunications capabilities are provided to communicate with module and systems operations as required to control total plant operation to meet delivery requirements.

System 11, the Coal Handling System, provides for the unloading of coal delivered to the plant either by barge or truck, reclaiming the coal from storage, reducing the size of coal, and transporting the coal to Coal Preparation and Feeding, System 1.

Raw coal is unloaded from barges by the barge unloading subsystem which is designed to unload up to ten 1500-ton capacity barges per shift. The coal is unloaded at an average rate of 1200 tons per hour on a five-day week basis. Coal is transferred by conveyor to a radial stacker which then produces a kidney-shaped coal pile containing live and dead storage. Coal is reclaimed from live storage and conveyed to a Bradford breaker where it is reduced in size to 2" x 0. Coal from trucks is unloaded into a chute from which it is conveyed to the Bradford breaker. Crushed coal from the Bradford breaker is transported to day storage silos from which it is transferred via vibrating belt conveyors to coal preparation and feeding, System 1, for further processing. Coal fines from the Bradford breaker are collected and sent to the gasification unit, System 2.

The purpose of System 12 is to store solid waste generated by facility operation during the facility life.

This system consists of a lined impounding pit sized to contain 20 years of solid waste. It includes the conveyor system to move the solids to the pit and a leachate recovery area to recover and pump leachate to the process condensate system.

Module descriptions are the subject of Section 4.

3.2 Facility Balances

The key material inputs and product outputs for the overall plant may be summarized as:

INPUTS:	Raw Coal	20,000 short tons/day
	98% Oxygen	16,400 short tons/day
	Raw Water Intake	10,000 gpm
	Imported Electric Power	425 MW
OUTPUTS:	Product Gas	898 MM SCFD
	By-product Sulfur	668 long tons/day
	Solids to Disposal (Wet)	4,335 tons/day
	Solids to Disposal (Dry)	3,252 tons/day

Table 3.1 gives the thermal efficiency for the facility. Table 3.2 gives the final product characteristics.

TABLE 3.1. CONVERSION EFFICIENCY KOPPERS-TOTZEK PROCESS 20,000 TPD FACILITY

	10^6 BTU/HR	PER CENT
INPUTS		
① COAL TO FACILITY	18,300	
② ELECTRIC POWER TO FACILITY	1,448	
OUTPUTS		
③ MBG FROM FACILITY	11,426	
④ COAL FINES FROM FACILITY	-0-	
EFFICIENCY		
COAL-TO MBG (③ ÷ ①) x 100%		62.4
OVERALL PRODUCT EFFICIENCY ③ ÷ (① + ②) x 100%		57.8
OVERALL FACILITY EFFICIENCY (③ + ④) ÷ (① + ②) x 100%		57.8

TABLE 3.2. PRODUCT CHARACTERISTICS

	VOLUME PER CENT
CARBON MONOXIDE	63.4
HYDROGEN	29.6
NITROGEN AND ARGON	1.5
CARBON DIOXIDE	4.9
METHANE	0.5
	100.0
HYDROGEN SULFIDE	4.0 PPM VOLUME
CARBONYL SULFIDE	16.0 PPM VOLUME
TOTAL SULFUR	20.0 PPM VOLUME
WATER VAPOR	7.0 LBS/MM SCF
HIGHER HEATING VALUE	305 BTU/SCF
TEMPERATURE	75 ^{o}F
PRESSURE	615 PSIA

4.0 MODULE DESCRIPTIONS

Each of the four modules in the plant consist of identical sequences of process systems as given in Table 2.1. Process flow diagrams and an equipment list are included in Section 5 for the principal process systems and such auxiliary systems, as cooling water and steam systems.

Each module receives 5000 TPD of coal from System 11, Coal Handling. The sequence of processing shown in Figure 4.1 is repeated in each of the four modules. Descriptions of each modular system are as follows.

4.1 System Descriptions

4.1.1 System 1 - Coal Preparation and Feeding

This system receives the rough processed coal from coal handling, System 11. The operations carried out in System 1 include: pulverizing coal to the required size, screening and recycle or oversized fractions, drying of processed coal to the required final moisture content, and transporting of the sized, dried coal to Gasification, System 2, for direct gasification. System 1 is shown schematically in Drawing Number 524-KT-01.

Crushed 2" x 0 coal is received from System 11 via a vibrating belt feeder. Tramp iron separators then remove ferrous metal items from the coal stream and discharge them through the tramp iron chute. The coal is then weighed on a belt scale after which it goes to a pulverizer-dryer. The pulverizers crush the coal to the required 70% through 200 mesh size, while simultaneously drying the coal to around 2% moisture. Drying is accomplished by a hot nitrogeous gas stream. The nitrogen gas stream is heated in a direct fired heater utilizing MBG product gas. Dried, pulverized coal is conveyed by the hot nitrogen gas stream to gasifier service bins. The pulverizer-dryers are controlled so as to maintain coal particle temperatures between 160-180°F, in order to avoid coking or devolatilization. Level controls on the gasifier service bins regulate the intermittent feeding of gasifier feed bins. Transport nitrogen gas is separated from the coal in the service bins prior to dust removal and subsequent venting. Gasifier feed bins are connected to the gasifier via variable speed screw feeders. These screw feeders discharge the coal to mixing heads where it is entrained in oxygen and low pressure steam, and transported via pipes to the gasifier burners. All fines are collected and returned to the service bins.

4.1.2 System 2 - Gasification

The Koppers-Totzek gasifier is of the high temperature, cocurrent entrained flow type. It is a proprietary unit licensed by Koppers Company. There are four feed points on the four-headed gasifiers, and two burner heads on each point. Each burner is arranged to produce a flame pattern which intersects the pattern of the adjacent burner on a head. Oxygen from the air

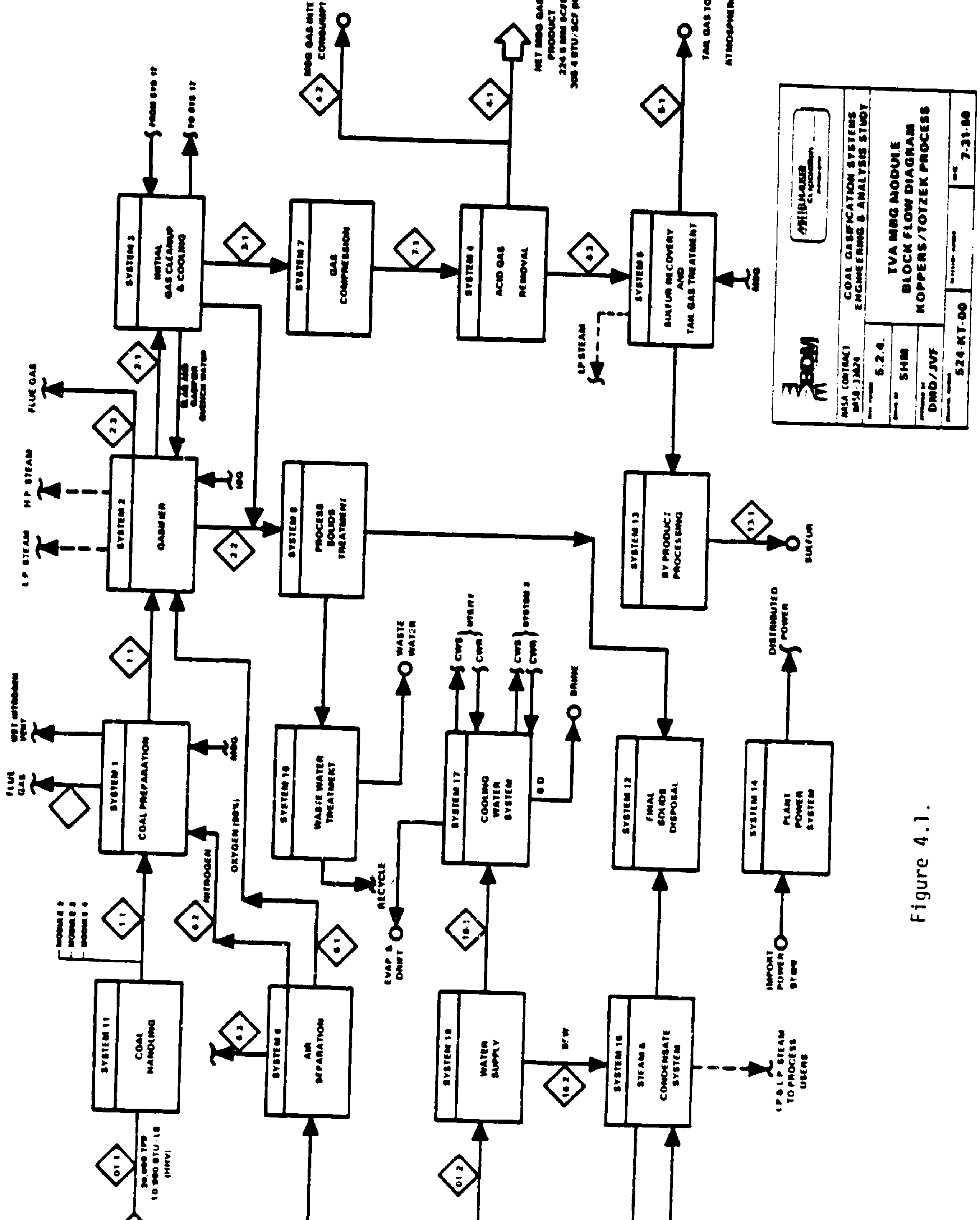
RAW COAL
AIR
RAW WATER
SYSTEM 11
COAL HANDLING
SYSTEM 6
AIR SEPARATION
SYSTEM 18
WATER SUPPLY
SYSTEM 16
STEAM & CONDENSATE SYSTEM
SYSTEM 1
COAL PREPARATION
SYSTEM 10
WASTE WATER TREATMENT
SYSTEM 17
COOLING WATER SYSTEM
SYSTEM 12
FINAL SOLIDS DISPOSAL
SYSTEM 14
PLANT POWER SYSTEM
SYSTEM 2
GASIFIER
SYSTEM 8
PROCESS SOLIDS TREATMENT
SYSTEM 13
BY PRODUCT PROCESSING
SYSTEM 3
INITIAL GAS CLEANUP & COOLING
SYSTEM 7
GAS COMPRESSION
SYSTEM 4
ACID GAS REMOVAL
SYSTEM 5
SULFUR RECOVERY AND TAIL GAS TREATMENT
FLUE GAS
LP STEAM
HP STEAM
NITROGEN
OXYGEN
WASTE WATER
BRINE
RECYCLE
EVAP & DRIFT
SULFUR
DISTRIBUTED POWER
IMPORT POWER
STEAM FM PRODUCERS
CONDENSATE FM USERS
TAIL GAS TO ATMOSPHERE
NET MBG GAS PRODUCT
MBG GAS INTERNAL CONSUMPTION
TVA MBG MODULE
BLOCK FLOW DIAGRAM
KOPPERS/TOTZEK PROCESS
COAL GASIFICATION SYSTEMS
ENGINEERING & ANALYSIS STUDY
524-KT-00
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Figure 4.1.

separation unit, System 6, and low pressure steam generated in the gasifier jacket, transport the pulverized coal to the gasifier. System 2 is shown schematically in Drawing Number 524-KT-02.

The coal, oxygen, and low pressure steam react to gasify the carbon and volatile matter in the coal. Due to the high temperature operation, as high as 3300°F, no tars, oils, phenols, etc., are produced. Each module contains eight operating and one spare gasifier train.

Approximately 50% of the ash in the coal leaves the gasifier in the form of liquid slag, out the bottom of the gasifier. Entrained slag droplets are quenched with water at the gasifier outlet, in order to drop the temperature below the ash fusion temperature. This prevents adherence of liquid ash to the waste heat boiler tubes. The gas, with entrained particulate ash, passes to the waste heat boiler located directly over the gasifier. Due to a reduction in velocity of the gas in the waste heat boiler, the heavier particles of ash are returned via a chute, to the slag quench tank below the gasifier. The waste heat boiler cools the gas to about 350°F, prior to cleanup. The waste heat boiler generates 49,500 pounds per hour of 1450 psig steam per gasifier.

The jacket of each gasifier produces 49,600 pounds per hour of low pressure steam from waste heat escaping the gasifier refractory lining. Of this, 7,065 pounds are used as feed to the reactor.

The oxygen feed rate is 0.90 O_2/lb dry coal. The higher heating value of the product gas produced is 305 Btu/SCF.

The Koppers-Totzek gasifiers operate at approximately 7 psig. Each module contains eight operating and one spare reactor.

4.1.3 System 3 - Initial Gas Cleanup and Cooling

The Koppers-Totzek gasification system includes a proprietary means for removal of particulate matter, as well as cooling the gas the final amount necessary to achieve temperatures compatible with sulfur removal systems. System 3 is included in Drawing Number 524-KT-02.

The raw gas exiting the waste heat boiler at around 350°F is washed in a pair of Venturi scrubbers arranged in series. The primary scrubber removes the bulk of the particles (around 90%). The gas from the secondary scrubber passes to the final gas cooler. The gas is cooled with water to around 95°F in this cooler; the total particulate removal efficiency of this system is around 99.9%. The cooled gas passes to System 7, compression.

The scrubbers and cooler produce a considerable quantity of particulate laden waste water. This water is constantly recycled after solids removal in a clarifier and cooling in a cooling tower. Due to losses in the cooling loop and water entrained in the slag stream from the quench tank, makeup water must constantly be provided. Gas cleanup and cooling are integral parts of the K-T system. Thus, there are eight operating and one spare system in each module. Figure 4.2 presents a balance of the water system around the gasifier and cleanup system.

4.1.4 System 7 - Compression

The purpose of this unit is to compress the MBG from initial gas cleanup and cooling, System 3, to a pressure sufficient to provide a plant boundary pressure of 600 psig. Water produced in the multi-stage compression process is collected and recycled to System 3 to provide a portion of the make-up required. The product gas compressors for the Koppers-Totzek module are motor driven machines. Outlet pressure from the compression unit is around 650 psig in order to provide for pressure losses in acid gas removal, dehydration, and gas metering.

Each module contains:

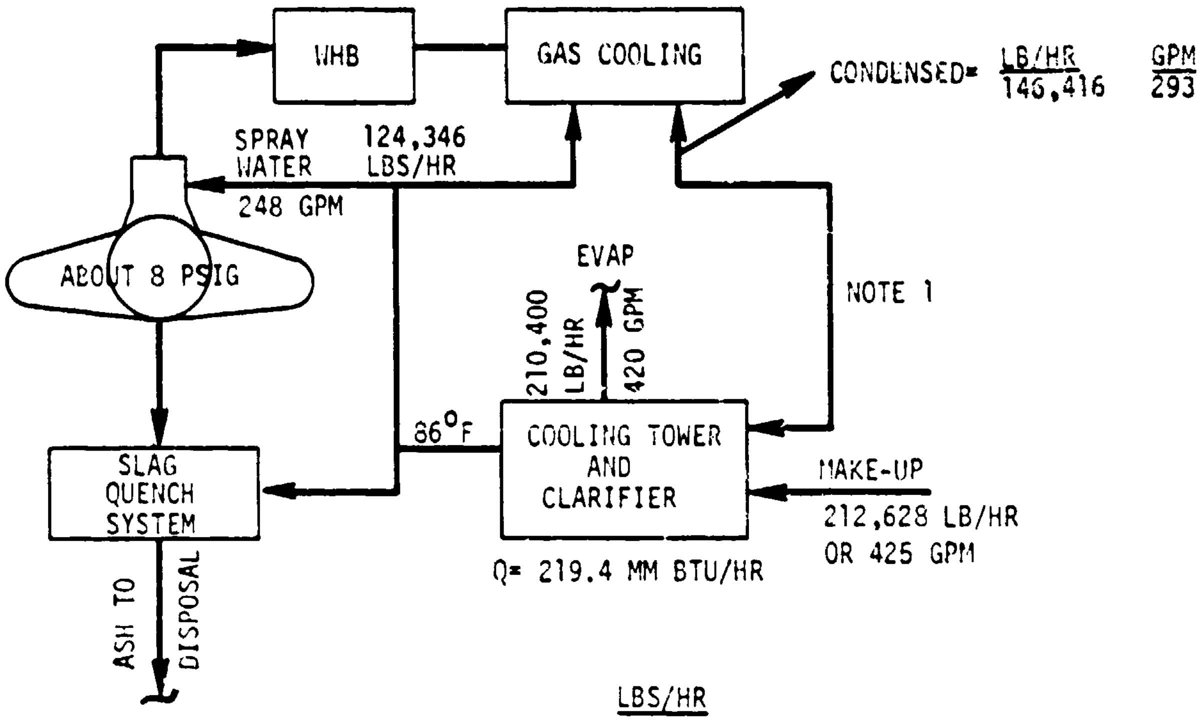
(1)	Axial Compressor	34,500 HP
(2)	2-Stage Centrifugal Compressor	34,600 HP
(3)	1-Stage Centrifugal Compressor	21,300 HP

System 7 is shown schematically in Drawing Number 524-KT-07.

4.1.5 System 4 - Acid Gas Removal

The acid gas removal system utilizes the Selexol solvent process and received 645,000 lbs/hr of sour gas at 100°F and 665 psia. The sweet (desulfurized) gas leaves the Selexol absorber at about 615 psia and a temperature of 60°F. The component removals across the absorber are:

	Inlet Gas (mols/hr)	Outlet Gas (mols/hr)	% Removal
Methane	125	125	0.00
Hydrogen	8,125	8,123	0.02
Carbon monoxide	17,406	17,374	0.18
Carbon dioxide	2,483	1,335	46.23
Hydrogen sulfide	433	1	99.77
Carbonyl sulfide	49	4	91.84
Nitrogen	420	420	0.00
Water	42	5	88.10
	28,958	27,387	



	LBS/HR	WT%
ASH	59,623	
UNBURNT CARBON	13,271	
TOTAL SOLIDS	72,814	75
WATER	24,298	25
TOTAL TO ASH DISPOSAL	97,192	100

WATER MAKE-UP REQUIREMENTS

	LBS/HR
WATER CONDENSED IN GAS COOLING =	146,416
WATER SPRAYED INTO GASIFIER =	124,346
WATER FROM GASIFIER EXIT GAS	22,070

	LBS/HR	GPM
WATER EVAPORATED	210,400	
WATER LEAVING W/SOLIDS	24,298	
WATER FROM GASIFIER EFF	-22,070	
NET MAKE-UP	212,628	425

$$\text{NO OF CYCLES} = \frac{212,628}{24,298} = 8.75$$

Figure 4.2. Process Cooling Tower Water Balance

The Selexol sulfur removal unit is a proprietary process licensed by Allied Chemical Company. The primary purpose of this system is to remove H_2S and COS from the product gas stream in order to obtain a sulfur concentration of not more than 200 ppmv. Secondarily, the process removes CO_2, which increases the gas heating value. System 4 is shown schematically in Drawing Number 524-KT-04.

The Selexol process removes sulfur compounds and carbon dioxide by means of countercurrent contact in an absorber. The physical absorption of the compounds to be removed is done using the dimethyl ether of polyethylene glycol as a solvent. Chilled solvent is used. Solvent chilling is accomplished by means of an absorption refrigeration system utilizing low pressure gasifier jacket steam.

CO_2 removal from the rich solvent leaving the absorber is accomplished by a series of successively lower pressure flashes. Flashed gas is recycled to the absorber inlet. Sulfur compounds are removed in the stripping column. The stripping column utilizes a steam heated reboiler. The stripper overhead gas, after cooling to about 120°F, flows to the sulfur recovery and tail gas treatment unit, System 5.

The sour gas from the Selexol unit is rich in CO_2, and at slightly above atmospheric pressure.

4.1.6 System 5 - Sulfur Recovery and Tail Gas Treatment

Acid gas from Acid Gas Removal, System 4, is fed to a Claus-type three-stage sulfur recovery unit utilizing a proprietary process for handling lean H_2S acid gases. Typically, in a Claus-type sulfur plant, the acid gas is first passed through a knockout drum before entering the reaction furnace. The chemistry of the process involves converting H_2S to elemental sulfur according to the following equation:

$$2H_2S + SO_2 \rightarrow 3S + 2H_2O$$

The reactions are exothermic, and the heat liberated generates steam in the reaction furnace boiler and in the sulfur condenser. The sulfur from each condenser is drained to a recovery pit in By-Product Processing, System 13, and the tail gas from the final condenser is fed to a Beavon tail gas treating unit where essentially complete removal of the remaining sulfur compounds is achieved before discharge to the atmosphere. The Beavon sulfur removal process reduces the sulfur content in the tail gas to less than 100 ppm. In this system, hydrogenation and hydrolysis are used to convert essentially all sulfur compounds to hydrogen sulfide. This gas is then cooled and passed into a contactor where the hydrogen sulfide is absorbed by the redox solution and oxidized to elemental sulfur. The reduced redox solution is reoxidized by contact with air and subsequently recirculated to the contactor. Elemental sulfur is removed in the air-blowing step as a froth which is pumped to a sulfur melter to be melted under pressure, separated from the redox solution and transferred to By-Product Processing, System 13. The decanted redox solution is returned to the system. System 5 is shown in Drawing Number 524-KT-05.

The system receives 48,370 lbs/hr of acid gas from the Selexol solvent regenerator at about 7 psig and 120°F.

The inlet gas composition is:

	Inlet Gas (mols/hr)
Hydrogen	3.3
Carbon monoxide	31.3
Carbon dioxide	1,148.9
Hydrogen sulfide	432.0
Carbonyl sulfide	44.0
Nitrogen	0.0
Water	153.0
	1,812.5

The recovery of by-product elemental sulfur from the sulfur recovery system is 167 long tons/day, which amounts to an overall sulfur recovery of about 99.9 percent.

4.1.7 System 6 - Air Separation

The purpose of this unit is to supply oxygen to the gasifiers. The process is non-proprietary and is offered in package form by several designer/manufacturers in the U. S. The gaseous oxygen stream of 98% purity is produced by distillation of liquified air. System 6 is shown schematically in Drawing Number 524-KT-06.

In the unit, which consists of multiple trains, 1,484,000 lbs/hr of atmospheric air is filtered and compressed to 110 psia by multi-stage compressors. Drivers are steam turbines with motors installed for start-up. The filtered-compressed air is cooled via cooled heat exchangers, then passes through reversing heat exchangers where it is cooled to slightly above its liquefaction temperature by heat exchange with the oxidant and waste gas streams, and by subsequent expansion through a turbine.

Water and carbon dioxide freeze out in the reversing exchangers, and are therefore removed from the inlet air stream. Subsequent switching of the exchanger sublimes the water and carbon dioxide into vapor which is vented as waste.

The cold air then enters the high pressure column for initial purification. The vapor at the top of the column is nitrogen containing 10 ppm of oxygen. Most of this is condensed in the high pressure condenser/low pressure reboiler and returned as reflux to the high pressure column. Some of this nitrogen vapor becomes the feed stream to the expansion turbine and some becomes low pressure product nitrogen gas after being superheated in the superheater and being warmed to about -150°F in a reversing heat exchanger.

Some of the nitrogen condensed in the condenser/reboiler becomes the liquid nitrogen product. It is first subcooled in the waste nitrogen core subcooler and then flashed into the liquid nitrogen separator. Liquid nitrogen product from the separator is transferred to the liquid nitrogen storage.

An impure reflux stream containing a small percentage of oxygen is withdrawn at an intermediate point in the column. It is subcooled and flashed into the top of the low pressure column.

The final purification of oxygen takes place in the low pressure column. The feeds to this column are impure reflux, and crude liquid oxygen from the high pressure column is subcooled and passed through the hydrocarbon absorbers before being flashed into the low pressure column. This procedures assures that all hydrocarbons are removed from the oxygen before purification. Processing the crude oxygen after it is liquified assures that the absorption is done at a relatively constant pressure and temperature and thus limits the possibility of accidental desorption.

As a further safeguard, a portion of the liquid oxygen in the low pressure sump is constantly withdrawn, passed through a guard hydrocarbon absorber and returned to the sump. This prevents trace quantities of hydrocarbons from accumulating in the low pressure sump.

The separated oxygen from the cold box (at 2 psig and 70°F) is compressed, in four stages of compression, to 40 psia for use in the gasifiers.

Each module contains a 23,000 HP axial air compressor powered by a 1450 psig superheated steam turbine, a 7500 HP centrifugal air compressor driven by a 25 psig steam turbine and a 1750 HP centrifugal oxygen compressor powered by an electrical motor. All turbine drives have electrical start-up motors.

The air separation plant was designed as two trains, each in operating service and each providing one-half of the oxygen requirement.

4.1.8 System 8 - Process Solids Treatment

Approximately 74,000 pounds per hour per module of ash and slag from the gasifier and gas cooling system along with biological sludges and solid wastes from process condensate treatment are treated in this unit.

Gravity settlers separate dense solids from the waste streams.

Float thickeners-clarifiers treat slurry from the gravity settlers. Thickener and coagulant aids are added to facilitate solid-liquid separation.

Rotary drum filters filter sludges from the process condensate treating systems and the float thickeners.

Recovered water is sent to the process condensate treating system, and solids are conveyed to final solids disposal.

4.1.9 System 13 - By-Product Processing

Sulfur is the only plant by-product other than ash/char solids which are disposed of on-site. Molten sulfur is pumped to a prilling tower in a continuously flowing circulation system. In the tower, sulfur is dispensed in droplets through nozzles. Droplets fall counter current to a stream of cooling air and solidify prior to landing in the bottom prill collection section. From the prill tower, sulfur is conveyed to a storage building from which it is transferred by truck or barge for sale. This system is illustrated in Drawing Number 524-KT-13.

4.1.10 System 14 - Plant Power System

This system is generally designed to receive medium voltage electrical power (4.16 KV, 6.9 KV or 13.8 KV) and provide the following functions:

(1) Develop the necessary voltage stepdown arrangement for plant requirements

(2) Distribute the necessary power to the plant equipment.

TVA's incoming substation transformers receive power from its primary distributed voltage switching station and step down this voltage to a medium voltage to supply the plant electrical power requirement for motors, heaters, lighting, and other miscellaneous loads.

The Medium Voltage Electrical Distribution Systems is a secondary selection system (double ended supply) with several medium voltage buses. Each medium voltage bus receives power from its respective incoming substation transformer through an incoming breaker and supplies power to the medium voltage distribution system through the feeder breakers.

The Low Voltage Electrical Distribution System typically consists of multiple 480 V double-ended load centers and 480 V motor control centers (MCC's) supplying the power to 480 V loads throughout the plant. Two load centers are interconnected through a normally open tie breaker. In the event of loss of one load center transformer or its feeder, the 480 V loads of the affected load center are fed by the second load center through the tie breaker.

Each load center consists of an incoming line section, load center transformer, and low voltage section with metal enclosed draw out power circuit breakers.

Load center transformers are air cooled, dry type, 150°F temperature rise, with delta connected primaries and wye connected secondaries. All load center feeder circuit breakers are 1600A frame and 50,000A RMS symmetrical interrupting capacity. The 480 V motor feeder breakers are electrically operated with instantaneous and long time trip units.

480 V MCC's consist of starters, feeder circuit breakers and control devices, assembled in a common structure with horizontal and vertical buses.

A 125 volt DC system supplies control power for medium voltage and 480 volt plant switchgear control, protective relaying and annunciation. The system also supplies power for emergency lighting.

4.1.11 System 15 - Steam Generation/Distribution

All of the plant steam is process generated.

Twenty-five psig steam (396,000 pounds per hour per module) is generated in the gasifier jackets. The gasifier steam requirement is 50,000 pounds per hour per module. Steam in excess of the gasifier requirements is used along with steam from System 5, Sulfur Recovery, to drive gas compressor in System 7, the refrigerant cooling water in System 4 and other plant uses. Waste heat boiler steam, generated at 1450 psig, is used to drive gas compressors and a small amount is let down to 550 psig for use in the sulfur recovery system. One hundred psig steam is generated in the sulfur recovery system and from gas compression turbine exhaust. It is used for reboiler heating in System 4 and to deaerate the steam condensate system. The steam system is given in Drawing Number 524-KT-10. The balance is shown in Figure 4.3.

4.1.12 System 16 - Water Supply

The raw water treatment unit is designed to provide treated and untreated water for the following facility water systems:

(1) Fire water
(2) Service water
(3) Potable water
(4) Cooling water
(5) Boiler feed water

Raw water is pumped from the river to a fire water-raw water storage tank.

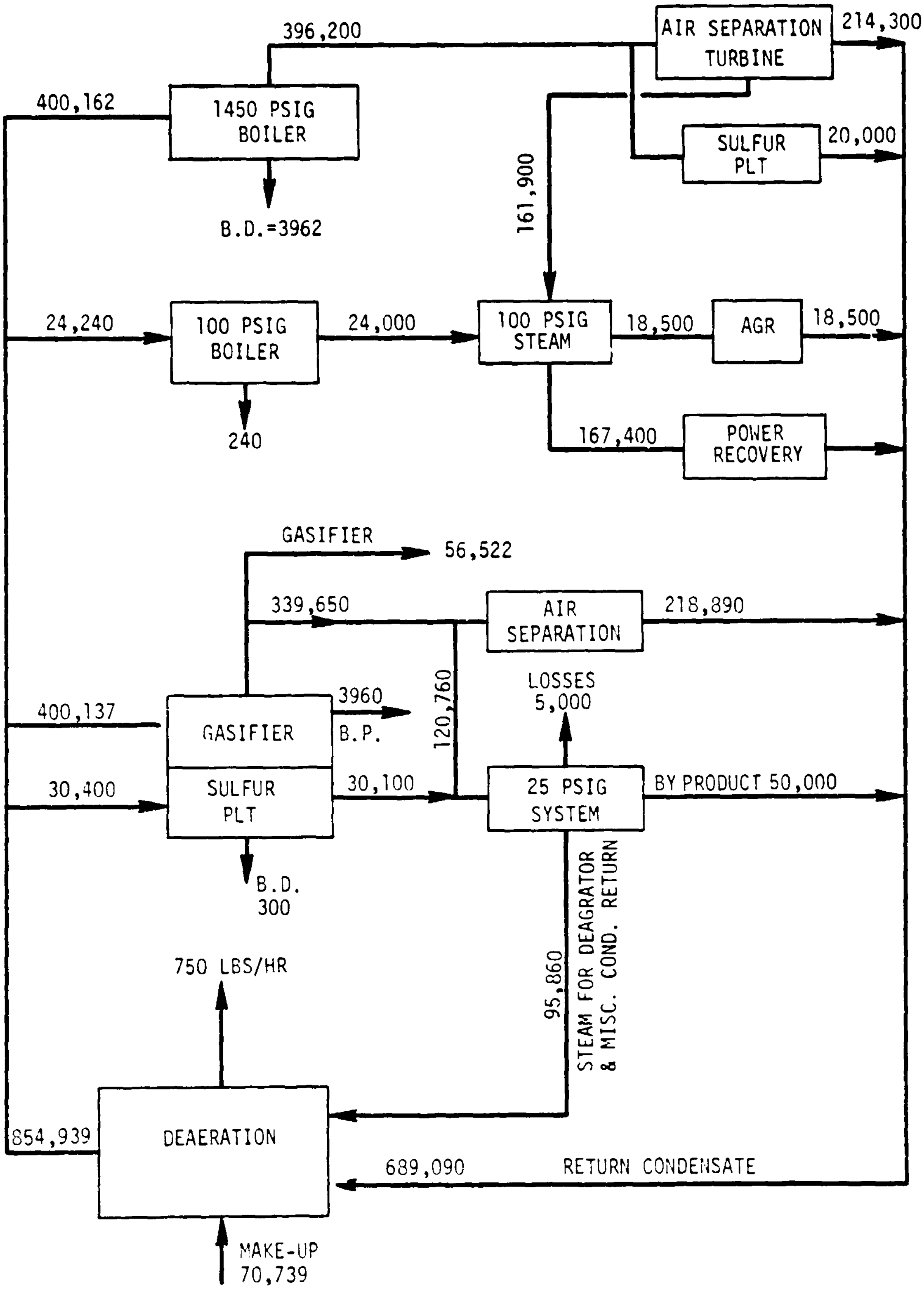


Figure 4.3. Steam System Balance-lbs/hr per Module

The raw water-fire water storage tank provides surge capacity for water treatment as well as storage capacity for fire water. During an emergency, fire water is pumped from the tank to the fire water heater system. The fire water pumps are motor driven and have a diesel engine driven spare. The spare pump is equipped with automatic start-up capability in case of power failure.

The raw water is pumped from the raw water-fire water storage tank to the softener-clarifier. Lime, alum, and polyelectrolyte from the clarifier bulk chemical storage and feed system are added to the softener-clarifier, which is equipped with an internal flocculation mechanism. The alum and polyelectrolyte aid in the removal of suspended solids from the raw water. Lime is added during the clarification step to "cold soften" the raw water. Chlorine is added to the raw water to inhibit algae growth in the clarifier and sand filters and reduce organic contamination.

The underflow from the clarifier is a one wt percent sludge and is pumped to solids treatment for further processing.

The clarified and softened raw water from the softener-clarifier flows to the self-backwashing sand filters where additional suspended solids are removed. A pressure differential across the filter bed initiates the backwash cycle. The backwash flows by gravity to the sand filter backwash sump and is recycled to the softener-clarifier. The filtered water flows to the filtered water storage tank and is utilized as cooling tower make-up for the process cooling tower as service water for general plant use, as feed to the demineralizer package, and as feed to the potable water system.

Water intended for potable services is chlorinated and again filtered to meet American Water Works Association (AWWA) standards and stored in a tank sized to hold a day's potable water requirements. The chlorine residual is maintained at 0.5-1.0 ppm free chlorine in the tank.

Filtered water intended as feed to the demineralizer package is injected with sodium sulfide to remove trace amounts of chlorine which adversely affect the demineralizer resins and after filtered through activated carbon to remove any remaining organic contaminants and dissolve iron.

In the demineralizer, the mineral salts present in the water are removed by ion exchange. A two-step demineralization system, utilizing strong cation and strong anion exchangers in series, is provided. A degasifier following the strong cation and magnesium, which the anion exchangers remove anions such as chloride and sulfate. The strong anion exchanger also removes silica. The degasifier is provided to remove carbon dioxide and other dissolved gases.

The mixed bed polisher is provided to remove silica to 0.02 ppm and to polish returned turbine condensate for reuse.

The boiler feed water deaerating heaters operate at 30 psig and 250^{o}F. The deaerators reduce the oxygen content of BFW to 0.005 cc/liter.

Hydrazine or sodium sulfite is injected into the storage compartment of the deaerators for chemical scavenging of any residual oxygen. Morpholine is injected into the suction of the boiler feed water pumps to protect the condensate systems.

The total water requirement is illustrated in Figure 4.4. Allowances for water treatment blowdown and contingency add to that shown to result in a total requirement of 2500 GPM per module.

Drawing Number 524-KT-16 shows System 16.

4.1.13 System 17 - Water Cooling

The purpose of this unit is to provide cooling water to the various process users in the facility.

The cooling tower system includes the tower and fans, side stream filters, circulating water pumps, cold water basin, blowdown system, chemical addition equipment, and distribution system.

Cooling water is pumped from the cold water basin, through the distribution system to the process heat exchangers where low-level, sensible heat is picked up, and back to the cooling tower. The cooling tower rejects low-level heat by evaporative cooling to air drawn through the cooling tower by the cooling tower fans.

A portion of the circulating water is passed through side stream filters to reduce loading to suspended solids, dirt and scale.

The dissolved solids level of the cooling water is maintained by a continuous blowdown stream to the process condensate system. Water level in the cooling tower basis is maintained by continuous make-up of the clean water from the raw water treatment system.

The blowdown stream is passed through a blowdown treatment system to recover chromate ions via ion exchange or by chemical reduction to chromium hydroxide and is sent to waste treatment for disposal.

Chlorine is added to the cooling water on a routine periodic basis to prevent algae growth. Chemical algicides are added periodically to further eliminate algae growth. Sulfuric acid is added to control pH, and zinc and chromate inhibitors are added to the cooling water for corrosion control. Occasionally, a polyphosphate dispersant is added to enhance the action of the inhibitors. This system is illustrated in Drawing Number 524-KT-17.

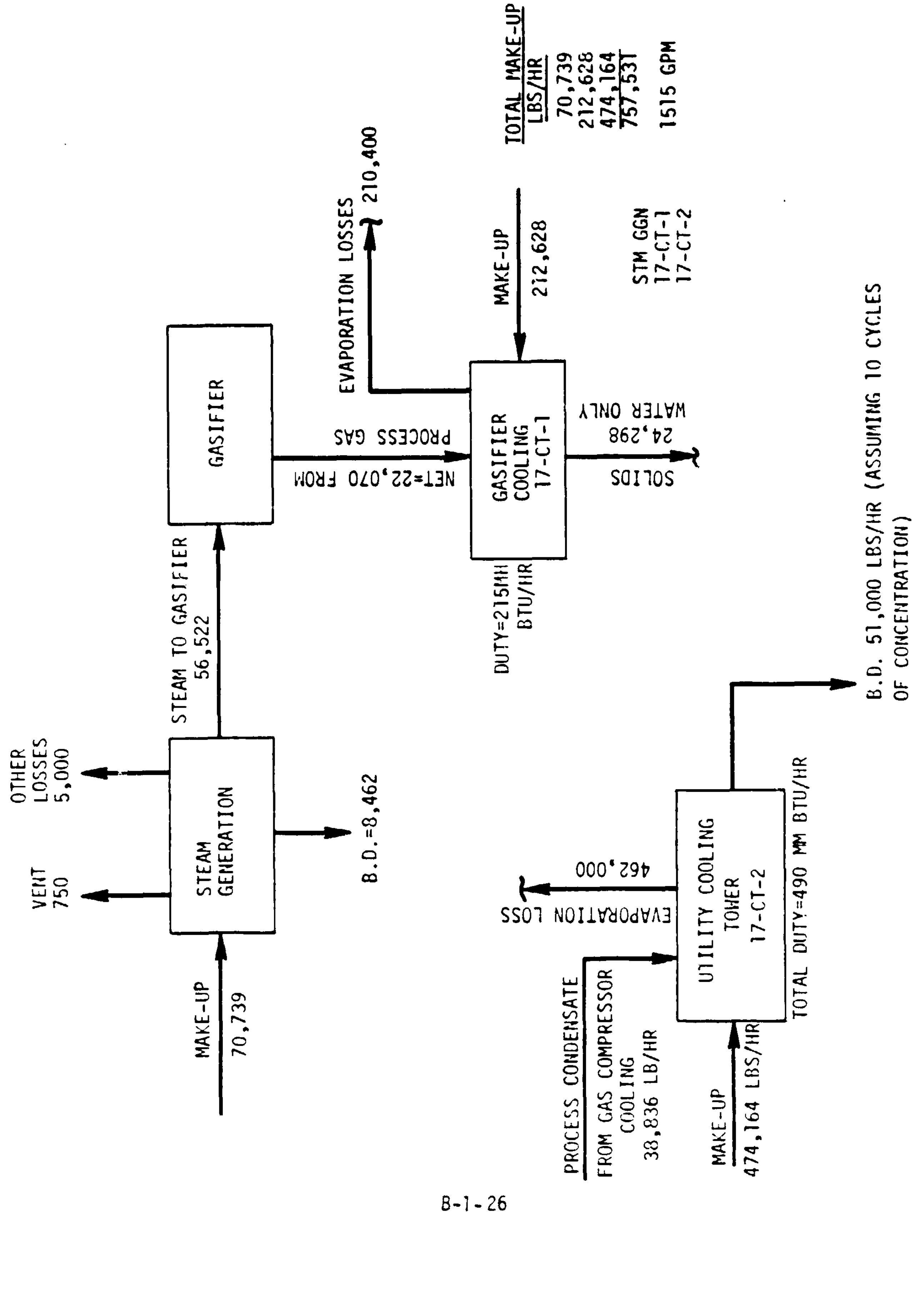


Figure 4.4. Overall Water Balance-lbs/hr per Module.

4.1.14 System 18 - Waste Water Treatment

The purpose of this unit is to collect and treat all plant liquid effluent streams. The plant design is predicated on "zero discharge" and permits recycle and reuse of treated water. Streams treated include the following:

(1) Oily water sewers
(2) Coal pile run-off
(3) Storm water run-off
(4) Demineralizer regenerant wastes and rinse water
(5) Cooling tower blowdown
(6) Sanitary waste water
(7) Gasifier slag quench drains
(8) Separated water from solids treatment
(9) Filtrate from biological treatment.

Process operations include:

(1) Oil Separator - streams containing free and dissolved oil and treated in a gravity separator utilizing an emulsion breaking chemical and heat to separate the oil-water mixture

(2) Sour Water Stripper - water streams with appreciable H_2O and HN_3 residuals are steam-stripped to remove these contaminants

(3) Equalization Basin - liquid streams with extremely high or low pH are mixed in an equalizing basis and treated with sulfuric acid or caustic to change the mixed pH to a value of 6.0 - 8.0

(4) Gravity Settling-Thickener - liquid streams with high suspended or dissolved solids are treated in a gravity settler-thickener and mixed with lime, alum, coagulant aids, and polymers to facilitate separation and thickening

(5) Multiple Effect Evaporation - neutralized wastes and brines are evaporated to recover water and concentrate the solids.

The recovered, treated water is used as make-up to cooling towers or raw water supply. The resultant solids are conveyed to the solids disposal system. System 18 is illustrated in Drawing Number 524-KT-18.

4.1.15 System 19 - General Facilities

The purpose of this unit is to provide equipment or services to support the gasification facility at the facility level.

This unit is a general facility category and provides the following equipment and services:

(1) Administration building
(2) Laboratories
(3) Change rooms
(4) Warehouses
(5) Maintenance buildings
(6) Operation centers
(7) Security offices
(8) Plant air facility
(9) Fire house
(10) Visitor reception
(11) Plant fencing
(12) Plant lighting
(13) Roads, bridges
(14) Docking facilities
(15) Interconnection pipe ways
(16) Fire protection network
(17) Flare stacks and headers
(18) Plant instrument air compressors
(19) Environmental monitoring
(20) Site preparation.

4.2 Module Balances

Material and energy balances have been determined for each module. Table 4.1 gives stream compositions and quantities for each intersystem stream. Table 4.2 gives an energy balance at the modular level.

TABLE 4-1
MATERIAL BALANCE
K-T PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			01-1		01-2		1-1	
STREAM ID			RAW COAL FEED		RAW WATER TO WATER TREATMENT		COAL TO GASIFIER	
	SYMBOL	FORMULA WEIGHT	LB-MOLS / HR	LBS / HR	LB-MOLS / HR	LBS / HR	LB-MOLS / HR	LBS / HR
CARBON	C	12.01		253,637				253,637
HYDROGEN	H_2	2.016		17,925				17,925
OXYGEN	O_2	32.0		23,901				23,901
NITROGEN & ARGON	N_2	28.016		5,761				5,761
SULFUR	S	32.06		15,449				15,449
CHLORINE	Cl	35.453		494				494
CARBON MONOXIDE	CO	28.01		-				-
CARBON DIOXIDE	CO_2	44.01		-				-
METHANE	CH_4	16.042		-				-
ETHYLENE	C_2H_4	28.052		-				-
ETHANE	C_2H_6	30.068		-				-
PROPYLENE	C_3H_6	42.078		-				-
PROPANE	C_3H_8	44.094		-				-
HYDROGEN SULFIDE	H_2S	34.076		-				-
CARBONYL SULFIDE	COS	60.075		-				-
CARBON DISULFIDE	CS_2	76.13		-				-
SULFUR DIOXIDE	SO_2	64.06		-				-
NITROUS OXIDE	NO_2	30.008		-				-
AMMONIA	NH_3	17.031		-				-
HYDROGEN CYANIDE	HCN	27.026		-				-
HYDROGEN CHLORIDE	HCl	36.461		-				-
NAPHTHA	-			-				-
TAR & OIL	-			-				-
ASH	-			59,650				59,650
OTHER SOLIDS				-				-
SUBTOTAL, DRY				376,817				376,817
WATER	H_2O	18.016		39,853		1,226,000		3,806
TOTAL, WET				416,670				380,623
GAS MOLECULAR WEIGHT				-			-	
TEMPERATURE, °F				-			140	
PRESSURE, PSIA				-			-	
SCFH				-			-	
GPM				-	2,453		-	

TABLE 4.1 (continued)
MATERIAL BALANCE
K-T PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			1-2		2-1		2-2	
STREAM ID			FLUE GAS		RAW GAS TO COOLING		ASH TO SOLIDS TREATMENT	
	SYMBOL	FORMULA WEIGHT	LB-MOLS / HR	LBS / HR	LB-MOLS / HR	LBS / HR	LB-MOLS / HR	LBS / HR
CARBON	C	12.01	-	-	-	-		-
HYDROGEN	H_2	2.016	-	-	8,125.4	16,380		-
OXYGEN	O_2	32.0	47.6	1,52[illegible].2	-	-		-
NITROGEN & ARGON	N_2	28.016	1,082.7	30,332.9	419.9	11,764		-
SULFUR	S	32.06	-	-	-	-		-
CHLORINE	Cl	35.453	-	-	-	-		-
CARBON MONOXIDE	CO	28.01	-	-	17,405.8	487,536		-
CARBON DIOXIDE	CO_2	44.01	345.1	15,187.9	2,483.2	109,286		-
METHANE	CH_4	16.042	-	-	125	2,005		-
ETHYLENE	C_2H_4	28.052	-	-	-	-		-
ETHANE	C_2H_6	30.068	-	-	-	-		-
PROPYLENE	C_3H_6	42.078	-	-	-	-		-
PROPANE	C_3H_8	44.094	-	-	-	-		-
HYDROGEN SULFIDE	H_2S	34.076	-	-	433.2	14,762.		-
CARBONYL SULFIDE	COS	60.075	-	-	48.7	2,926.		-
CARBON DISULFIDE	CS_2	76.13	-	-	-	-		-
SULFUR DIOXIDE	SO_2	64.06	0.1	6.4	-	-		-
NITROUS OXIDE	NO	30.008	-	-	-	-		-
AMMONIA	NH_3	17.031	-	-	-	-		-
HYDROGEN CYANIDE	HCN	27.026	-	-	-	-		-
HYDROGEN CHLORIDE	HCl	36.461	-	-	14.3	521.		-
NAPHTHA	-		-	-	-	-		-
TAR & OIL	-		-	-	-	-		-
ASH	-		-	-	-	-		59,650
OTHER SOLIDS					-	-		14,334
SUBTOTAL, DRY			1,475.5	47,050.4	29,055.5	645,180.		73,984
WATER	H_2O	18.016	197.5	3,558.2	10,326.5	186,042.		24,661
TOTAL, WET			1,673.0	122,697	39,382.0	831,222.		98,645
GAS MOLECULAR WEIGHT			30.6		21.1			-
TEMPERATURE, °F			600		350			-
PRESSURE, PSIA			14.4		15.4			-
SCFH			635,740		14,952,083			-
GPM			-		-			49

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TABLE 4.1 (continued)
MATERIAL BALANCE
X-T PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			2-3		3-1		4-1	
STREAM ID			FLUE GAS		RAW GAS TO COMPRESSION		MBG GAS PRODUCT	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01	-	-	-	-	-	-
HYDROGEN	H_2	2.016	-	-	8,125.4	16,381.	7,308.6	14,734
OXYGEN	O_2	32.0	125.9	4,029	-	-	-	-
NITROGEN & ARGON	N_2	28.016	2,863.3	80,218	419.9	11,764.	377.9	10,587
SULFUR	S	32.06	-	-	-	-	-	-
CHLORINE	Cl	35.453	-	-	-	-	-	-
CARBON MONOXIDE	CO	28.01	-	-	17,405.8	487,536.	15,634.[illegible]	437,917
CARBON DIOXIDE	CO_2	44.01	912.2	40,146	2,483.2	109,286.	1,200.6	52,838
METHANE	CH_4	16.042	-	-	125.	2,005.	112.5	1,804
ETHYLENE	C_2H_4	28.052	-	-	-	-	-	-
ETHANE	C_2H_6	30.068	-	-	-	-	-	-
PROPYLENE	C_3H_6	42.078	-	-	-	-	-	-
PROPANE	C_3H_8	44.094	-	-	-	-	-	-
HYDROGEN SULFIDE	H_2S	34.076	-	-	433.2	14,762.	0.9511	32.41
CARBONYL SULFIDE	COS	60.075	-	-	48.7	2,926.	3.977	238.90
CARBON DISULFIDE	CS_2	76.13	-	-	-	-	-	-
SULFUR DIOXIDE	SO_2	64.06	0.3651	16.98	-	-	-	-
NITROUS OXIDE	NO	30.008	-	-	-	-	-	-
AMMONIA	NH_3	17.031	-	-	-	-	-	-
HYDROGEN CYANIDE	HCN	27.026	-	-	-	-	-	-
HYDROGEN CHLORIDE	HCl	36.461	-	-	-	-	-	-
NAPHTHA	-		-	-	-	-	-	-
TAR & OIL	-		-	-	-	-	-	-
ASH	-		-	-	-	-	-	-
OTHER SOLIDS			-	-	-	-	-	-
SUBTOTAL, DRY			3,901.7	124,410	29,041.2	644,660	24,638.8	518,151
WATER	H_2O	18.016	405.98	7,314	2,244.4	40,435	3.6	64.8
TOTAL, WET			4,[illegible]07.6	131,724	31,285.6	685,095	24,642.4	518,216
GAS MOLECULAR WEIGHT			30.6		21.9		21.0	
TEMPERATURE, °F			400		100		60	
PRESSURE, PSIA			14.4		14.9		615	
SCFH			1,634,993		11,878,140.		9,353,269	
CFM			-		-		-	

TABLE 4.1 (continued)
MATERIAL BALANCE
K-T PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			4-2		4-3		5-1	
STREAM ID			MBG GAS INTERNAL CONSUMPTION		ACID GAS TO SUL[illegible] [illegible]COVERY		SULFUR PLANT TAIL GAS	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01	-	-	-	-	-	-
HYDROGEN	H_2	2.016	813.5	1,640	3.3	7.	24.6	49
OXYGEN	O_2	32.0	-	-	-	-	-	-
NITROGEN & ARGON	N_2	28.016	42.0	1,177	-	-	954.0	26,727
SULFUR	S	32.06	-	-	-	-	-	-
CHLORINE	Cl	35.453	-	-	-	-	-	-
CARBON MONOXIDE	CO	28.01	1,740.2	48,743	31.3	877.	-	-
CARBON DIOXIDE	CO_2	44.01	133.6	5,880	1148.9	50,563.	1,175.3	51,725
METHANE	CH_4	16.042	12.5	201	-	-	-	-
ETHYLENE	C_2H_4	28.052	-	-	-	-	-	-
ETHANE	C_2H_6	30.068	-	-	-	-	-	-
PROPYLENE	C_3H_6	42.078	-	-	-	-	-	-
PROPANE	C_3H_8	44.094	-	-	-	-	-	-
HYDROGEN SULFIDE	H_2S	34.076	0.1059	3.61	432.14	14,726.	0.0023	0.0784
CARBONYL SULFIDE	COS	60.075	0.4427	26.59	44.28	2,660.	-	-
CARBON DISULFIDE	CS_2	76.13	-	-	-	-	-	-
SULFUR DIOXIDE	SO_2	64.06	-	-	-	-	-	-
NITROUS OXIDE	NO_2	30.008	-	-	-	-	-	-
AMMONIA	NH_3	17.031	-	-	-	-	-	-
HYDROGEN CYANIDE	HCN	27.026	-	-	-	-	-	-
HYDROGEN CHLORIDE	HCl	36.461	-	-	-	-	-	-
NAPHTHA	-		-	-	-	-	-	-
TAR & OIL	-		-	-	-	-	-	-
ASH	-		-	-	-	-	-	-
OTHER SOLIDS			-	-	-	-	-	-
SUBTOTAL, DRY			2,742.3	57,671	1,659.92	68,833.	2,153.9	78,502
WATER	H_2O	18.016	0.9986	17.99	153.4	2,764.	147.3	2,654
TOTAL, WET			2,743.6	57,689	1,813.32	71,597.	2,301.2	81,156
GAS MOLECULAR WEIGHT			21.0		39.48		35.3	
TEMPERATURE, °F			60		120		100	
PRESSURE, PSIA			615		20		14.4	
SCFH			1,041,247		688,461.		873,443	
GPM			-		-		-	

TABLE 4.1 (continued)
[illegible]
PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			6-1		6-2		6-3	
STREAM ID			OXIDANT TO GASIFIER		INERT GAS TO COAL PREPARATION		AIR SEPARATION VENT	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01	-	-	-	-	-	-
HYDROGEN	H_2	2.016	-	-	-	-	-	-
OXYGEN	O_2	32.0	10,501.4	336,045	-	-	-	-
NITROGEN & ARGON	N_2	28.016	214.3	6,004	3,000	84,048	36,270	1,016,140
SULFUR	S	32.06		-	-	-	-	-
CHLORINE	Cl	35.453	-	-	-	-	-	-
CARBON MONOXIDE	CO	28.01	-	-	-	-	-	-
CARBON DIOXIDE	CO_2	44.01	-	-	-	-	-	-
METHANE	CH_4	16.042	-	-	-	-	-	-
ETHYLENE	C_2H_4	28.052	-	-	-	-	-	-
ETHANE	C_2H_6	30.068	-	-	-	-	-	-
PROPYLENE	C_3H_6	42.078	-	-	-	-	-	-
PROPANE	C_3H_8	44.094	-	-	-	-	-	-
HYDROGEN SULFIDE	H_2S	34.076	-	-	-	-	-	-
CARBONYL SULFIDE	COS	60.075	-	-	-	-	-	-
CARBON DISULFIDE	CS_2	76.13	-	-	-	-	-	-
SULFUR DIOXIDE	SO_2	64.06	-	-	-	-	-	-
NITROUS OXIDE	NO	30.008	-	-	-	-	-	-
AMMONIA	NH_3	17.031	-	-	-	-	-	-
HYDROGEN CYANIDE	HCN	27.026	-	-	-	-	-	-
HYDROGEN CHLORIDE	HCl	36.461	-	-	-	-	-	-
NAPHTHA	-		-	-	-	-	-	-
TAR & OIL	-		-	-	-	-	-	-
ASH	-		-	-	-	-	-	-
OTHER SOLIDS			-	-	-	-	-	-
SUBTOTAL, DRY			10,715.7	342,049	3,000	84,048	36,270	1,016,140
WATER	H_2O	18.016	-	-	0	0		
TOTAL, WET			10,715.7	342,049	3,000	84,048	36,270	1,016,140
GAS MOLECULAR WEIGHT			31.92		28.0		28.0	
TEMPERATURE, °F			140		90		90	
PRESSURE, PSIA			21.6		14.4		144	
SCFH			4,068,408		1,140,000		-	
GPM			-		-		13,782,600	

TABLE 4.1 (continued)
MATERIAL BALANCE
K-T PROCESS
INTEGRATED FACILITY/MODE [illegible] DEFINITION

STREAM NUMBER			7-1		11-1		12-1	
STREAM ID			SOUR GAS TO ACID GAS REMOVAL		COAL TO COAL PREPARATION		SOLIDS TO DISPOSAL	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01	-	-		253,637		-
HYDROGEN	H_2	2.016	8,125.4	16,381.		17,925		-
OXYGEN	O_2	32.0	-	-		23,901		-
NITROGEN & ARGON	N_2	28.016	419.9	11,764.		5,761		-
SULFUR	S	32.06	-	-		15,449		-
CHLORINE	Cl	35.453	-	-		494		-
CARBON MONOXIDE	CO	28.01	17,405.8	487,536.		-		-
CARBON DIOXIDE	CO_2	44.01	2,483.2	109,286.		-		-
METHANE	CH_4	16.042	125.	2,005.		-		-
ETHYLENE	C_2H_4	28.052	-	-		-		-
ETHANE	C_2H_6	30.068	-	-		-		-
PROPYLENE	C_3H_6	42.078	-	-		-		-
PROPANE	C_3H_8	44.094	-	-		-		-
HYDROGEN SULFIDE	H_2S	34.076	433.2	14,762.		-		-
CARBONYL SULFIDE	COS	60.075	48.7	2,926.		-		-
CARBON DISULFIDE	CS_2	76.13	-	-		-		-
SULFUR DIOXIDE	SO_2	64.06	-	-		-		-
NITROUS OXIDE	NO	30.008	-	-		-		-
AMMONIA	NH_3	17.031	-	-		-		-
HYDROGEN CYANIDE	HCN	27.026	-	-		-		-
HYDROGEN CHLORIDE	HCl	36.461	-	-		-		-
NAPHTHA	-		-	-		-		-
TAR & OIL	-		-	-		-		-
ASH	-		-	-		59,650		59,650
OTHER SOLIDS			-	-		-		14,334
SUBTOTAL, DRY			29,041.2	644,660.		376,817		73,984
WATER	H_2O	18.016	41.6	749.		39,853		24,661
TOTAL, WET			29,082.8	645,409.		416,670		98,645
GAS MOLECULAR WEIGHT			22.19			-		-
TEMPERATURE, °F			100.			-		-
PRESSURE, PSIA			665.			-		-
SCFH			11,041,832.			-		-
GPM			-			-		49

TABLE 4.1 (continued)
MATERIAL BALANCE
K-T PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			13-1		16-1		16.2	
STREAM ID			SULFUR TO STORAGE		MAKEUP WATER TO COOLING WATER SYSTEM		MAKEUP WATER TO STEAM & CONDENSATE SYSTEM	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01	-	-				
HYDROGEN	H_2	2.016	-	-				
OXYGEN	O_2	32.0	-	-				
NITROGEN & ARGON	N_2	28.016	-	-				
SULFUR	S	32.06	476.4	15,273				
CHLORINE	Cl	35.453	-	-				
CARBON MONOXIDE	CO	28.01	-	-				
CARBON DIOXIDE	CO_2	44.01	-	-				
METHANE	CH_4	16.042	-	-				
ETHYLENE	C_2H_4	28.052	-	-				
ETHANE	C_2H_6	30.068	-	-				
PROPYLENE	C_3H_6	42.078	-	-				
PROPANE	C_3H_8	44.094	-	-				
HYDROGEN SULFIDE	H_2S	34.076	-	-				
CARBONYL SULFIDE	COS	60.075	-	-				
CARBON DISULFIDE	CS_2	76.13	-	-				
SULFUR DIOXIDE	SO_2	64.06	-	-				
NITROUS OXIDE	NO	30.008	-	-				
AMMONIA	NH_3	17.031	-	-				
HYDROGEN CYANIDE	HCN	27.026	-	-				
HYDROGEN CHLORIDE	HCl	36.461	-	-				
NAPHTHA	-		-	-				
TAR & OIL	-		-	-				
ASH	-		-	-				
OTHER SOLIDS			-	-				
SUBTOTAL, DRY			476.4	15,273				
WATER	H_2O	18.016	-	-		686,790		70,740
TOTAL, WET			476.4	15,273				
GAS MOLECULAR WEIGHT			-					
TEMPERATURE, °F			250					
PRESSURE, PSIA			-					
SCFH			-					
GPM			-		1,370		140	

TABLE 4.2
MODULE ENERGY BALANCE, 10^6 BTU PER HOUR
K-T PROCESS

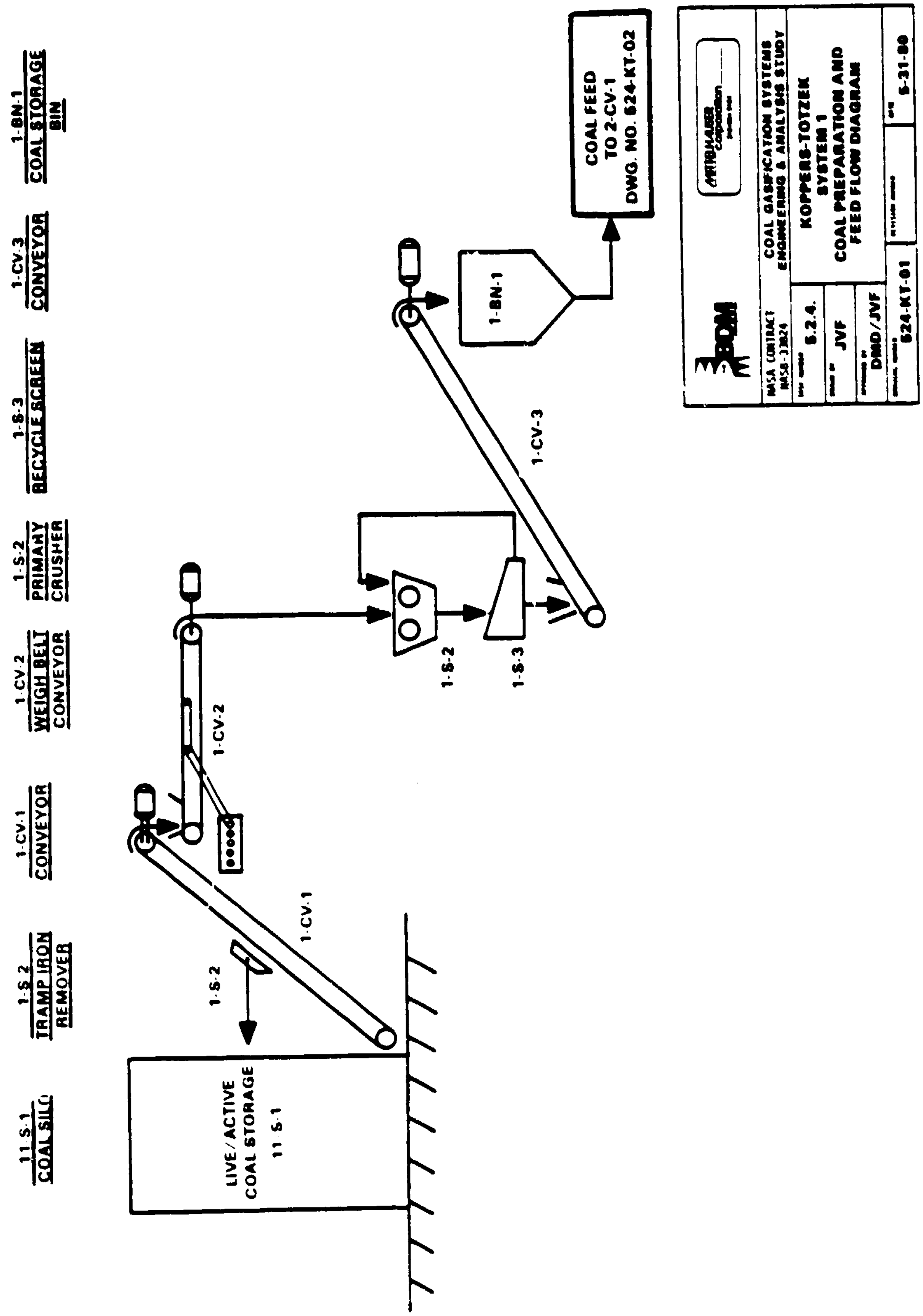
	PHASE	HHV	LATENT	SENSIBLE	TOTAL
ENTHALPY BALANCE					
INLETS					
STREAM Coal	Solid	4575.		0	4575.
Air to Air Sep'n	Gas		19.5	0	19.5
Raw Water	Liquid			0	
SUBTOTAL IN					4594.5
OUTLETS					
STREAM MBG	Gas	2856.5		0	2856.5
Ash	Solid			0	0
Tail Gas	Gas		2.8	0.8	3.6
Air Sep'n Vent	Gas		38.2	53.9	92.1
Flue Gas	Gas		15.0	17.0	32.0
Sulfur	Solid	60.8		0.5	61.3
SUBTOTAL OUT					3597.2
NET INLET-OUTLET					997.3
HEAT AND SHAFT WORK					
ELECTRIC POWER					362.3
SHAFT WORK					0
HEAT REJECTION			-1113.4	-336.5	-1449.9
HEAT INPUT (STEAM)					
RADIATION/FUGITIVE LOSS					-25.0
SUBTOTAL NET VALUE					-1112.6
TOTAL ABSOLUTE VALUE					1112.6

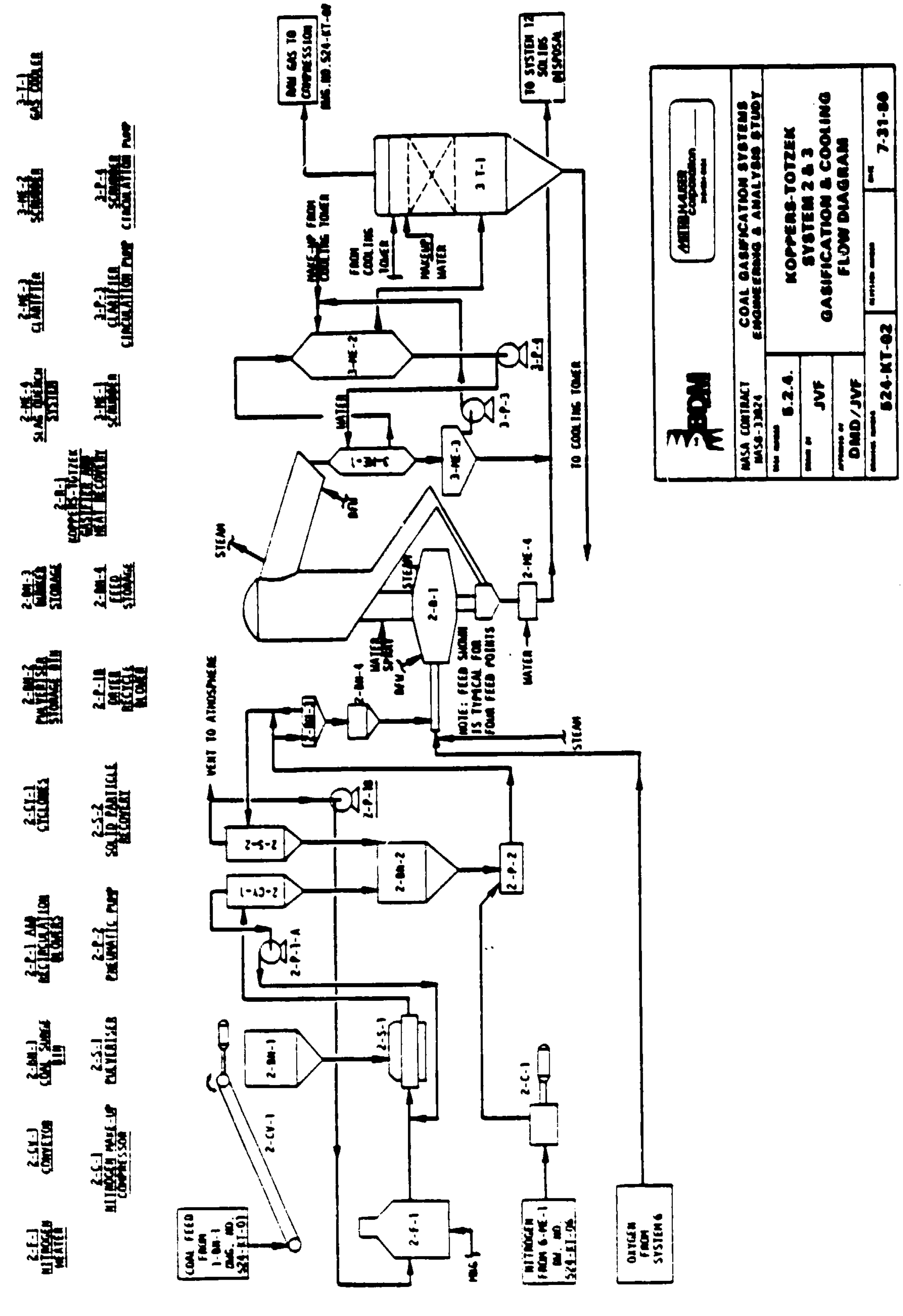
BALANCE: $\frac{\text{NET ENTHALPY + NET HEAT \& SHAFT WORK}}{\text{TOTAL ABSOLUTE VALUE OF HEAT \& SHAFT WORK}} \times 100\% = 10.4\%$

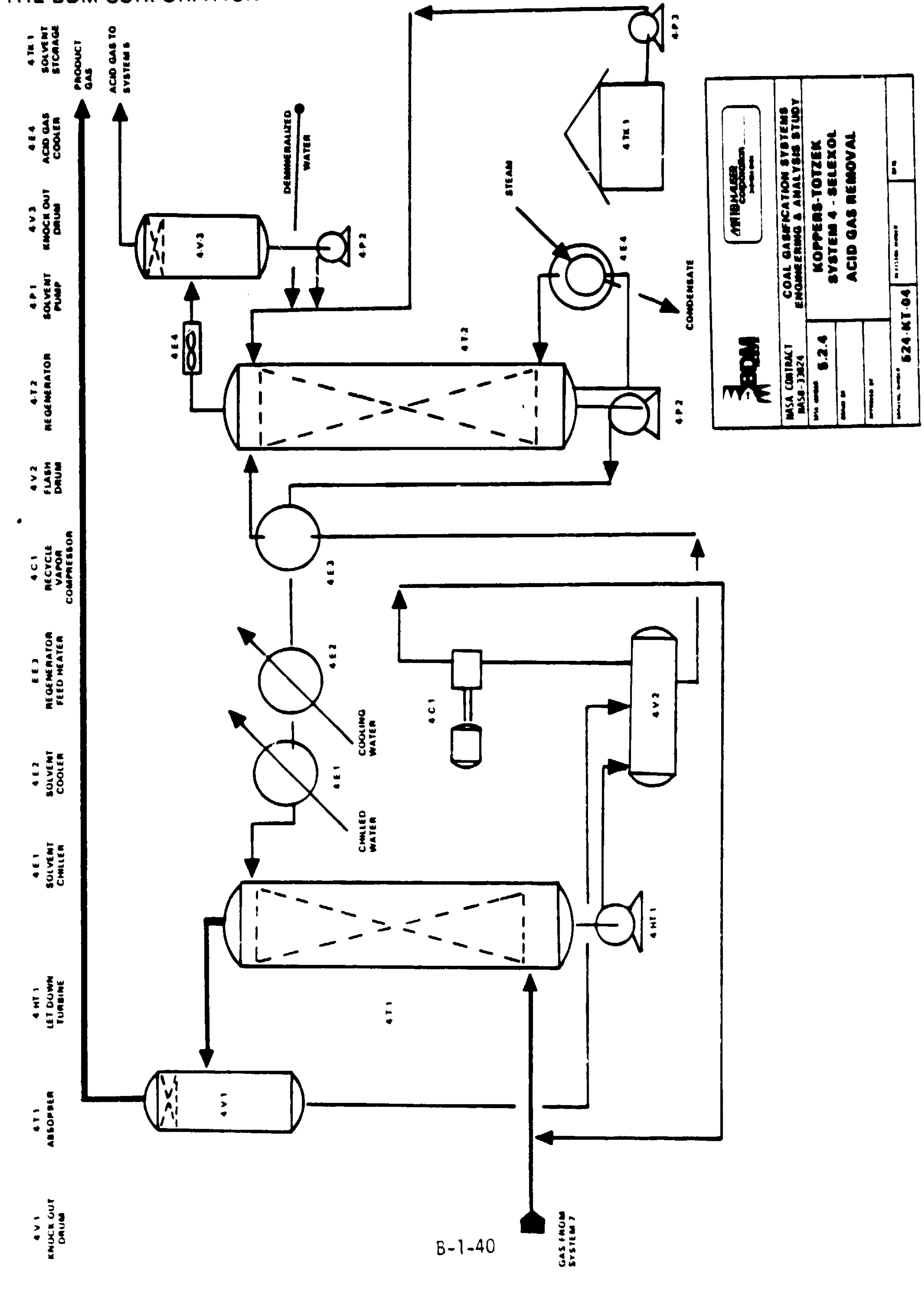
BASIS: $60^{\circ}F$, LIQUID WATER

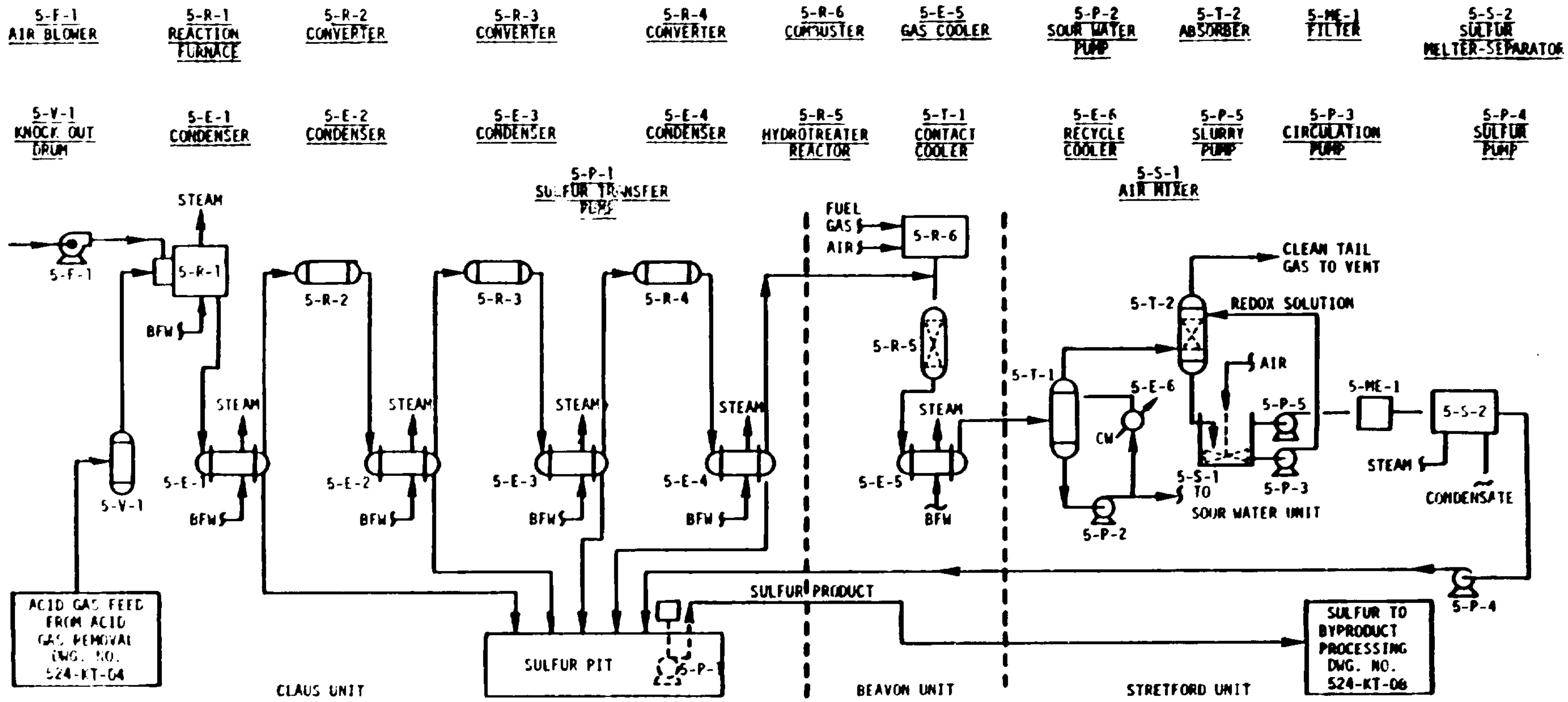
5.0 PROCESS FLOW DIAGRAM AND EQUIPMENT LIST

This section contains the process flow diagrams and the list of equipment for each module. The facility contains four times the quantity shown here except for the coal silos which are on a facility basis and System 5, which has two trains in Module 1 and only one train in subsequent modules.


11-S-1
COAL SILO
1-S-2
TRAMP IRON REMOVER
1-CV-1
CONVEYOR
1-CV-2
WEIGH BELT CONVEYOR
1-S-2
PRIMARY CRUSHER
1-S-3
RECYCLE SCREEN
1-CV-3
CONVEYOR
1-BN-1
COAL STORAGE BIN
LIVE/ACTIVE
COAL STORAGE
11-S-1
1-S-2
1-CV-1
1-CV-2
1-S-2
1-S-3
1-CV-3
1-BN-1
COAL FEED
TO 2-CV-1
DWG. NO. 524-KT-02
Mittelhauser Corporation
COAL GASIFICATION SYSTEMS
ENGINEERING & ANALYSIS STUDY
KOPPERS-TOTZEK
SYSTEM 1
COAL PREPARATION AND
FEED FLOW DIAGRAM
NASA CONTRACT
5.2.4.
JVF
DMD/JVF
524-KT-01
5-31-80


KOPPERS-TOTZEK
SYSTEM 2 & 3
GASIFICATION & COOLING
FLOW DIAGRAM
COAL GASIFICATION SYSTEMS
ENGINEERING & ANALYSIS STUDY
NASA CONTRACT
524-KT-02
7-31-80
DMD/JVF
TO COOLING TOWER
VENT TO ATMOSPHERE
OXYGEN FROM SYSTEM 6


4 V 1 KNOCK OUT DRUM
4 T 1 ABSORBER
4 HT 1 LET DOWN TURBINE
4 E 1 SOLVENT CHILLER
4 E 2 SOLVENT COOLER
4 E 3 REGENERATOR FEED HEATER
4 C 1 RECYCLE VAPOR COMPRESSOR
4 V 2 FLASH DRUM
4 T 2 REGENERATOR
4 P 1 SOLVENT PUMP
4 V 3 KNOCK OUT DRUM
4 E 4 ACID GAS COOLER
4 TK 1 SOLVENT STORAGE
PRODUCT GAS
ACID GAS TO SYSTEM 6
DEMINERALIZED WATER
STEAM
CONDENSATE
COOLING WATER
CHILLED WATER
GAS FROM SYSTEM 7
NASA CONTRACT NAS8-33824
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
KOPPERS-TOTZEK SYSTEM 4 - SELEXOL ACID GAS REMOVAL
6.2.4
524-KT-04



BDM

METTBHAUSER CORPORATION

COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY

5.2.4.

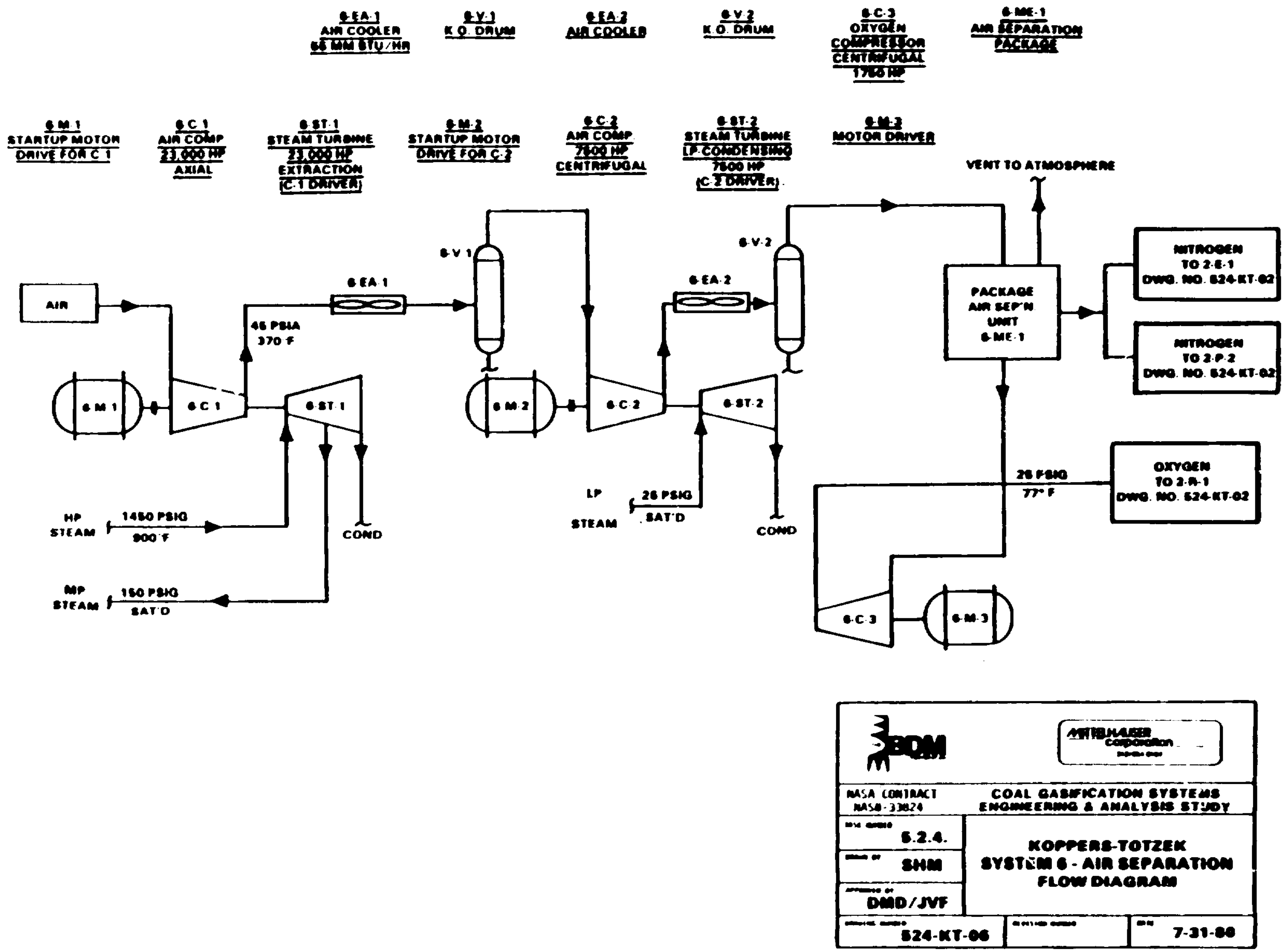
JVF

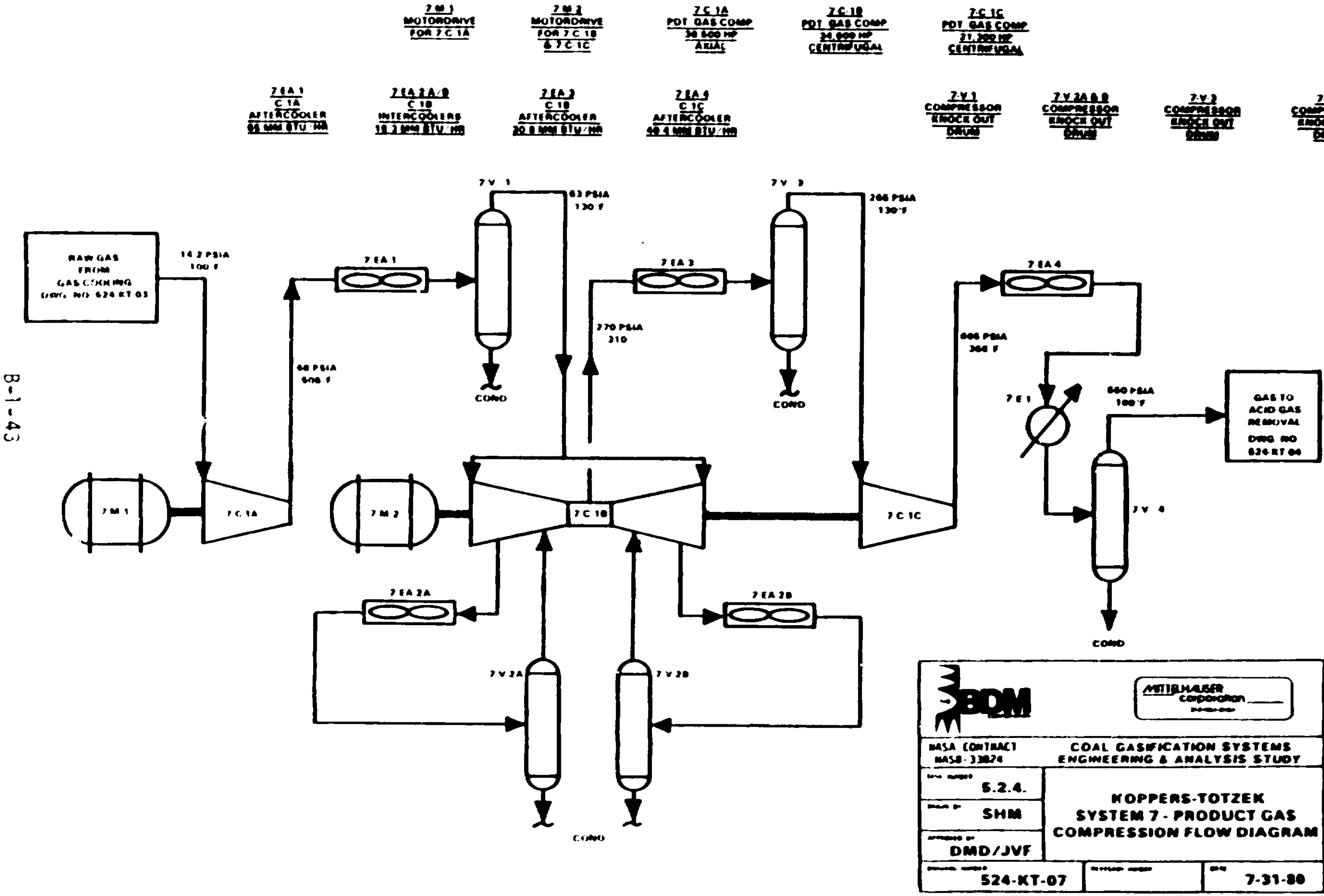
MOD/JVF

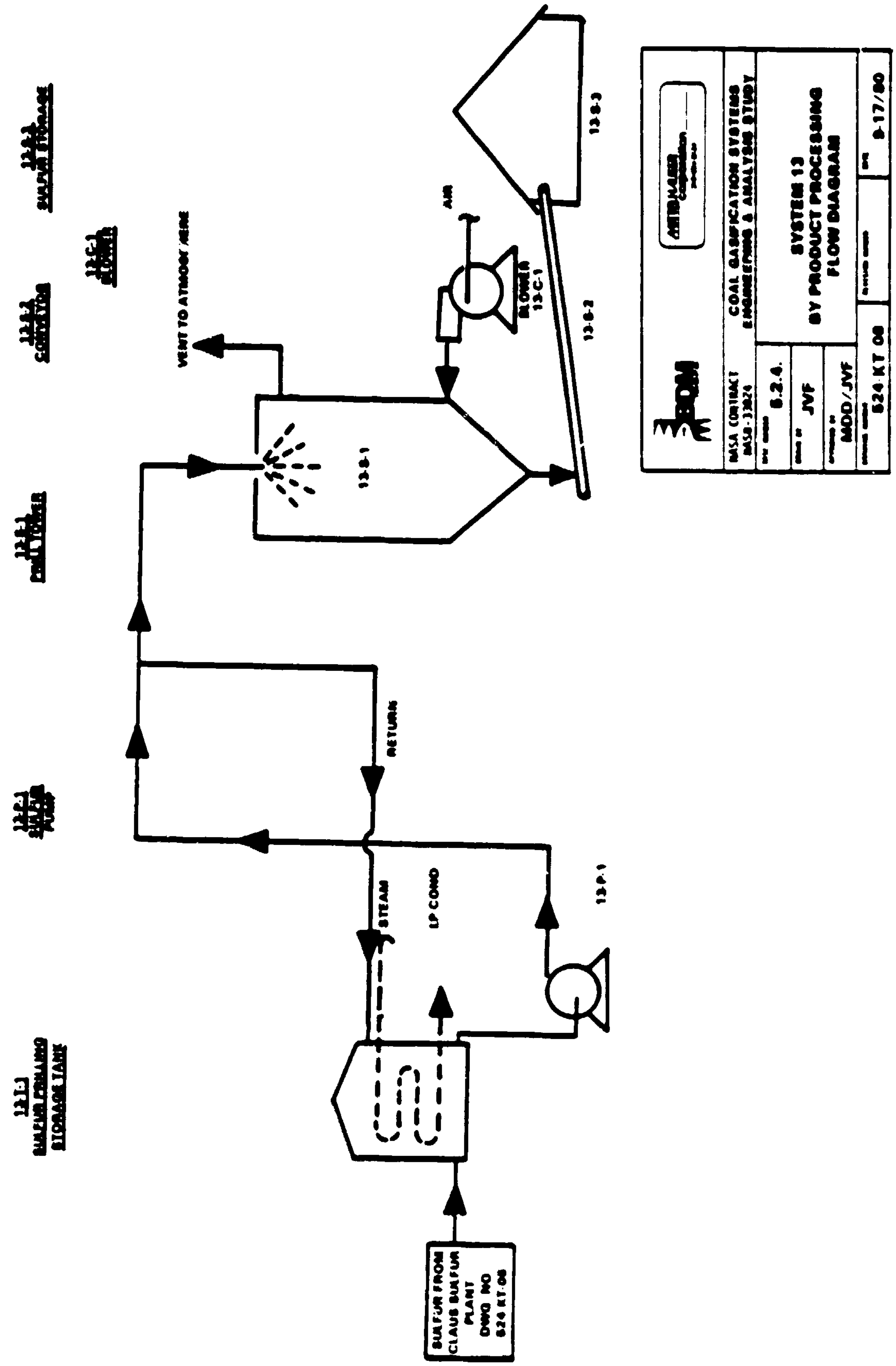
SYSTEM 5
SULFUR RECOVERY

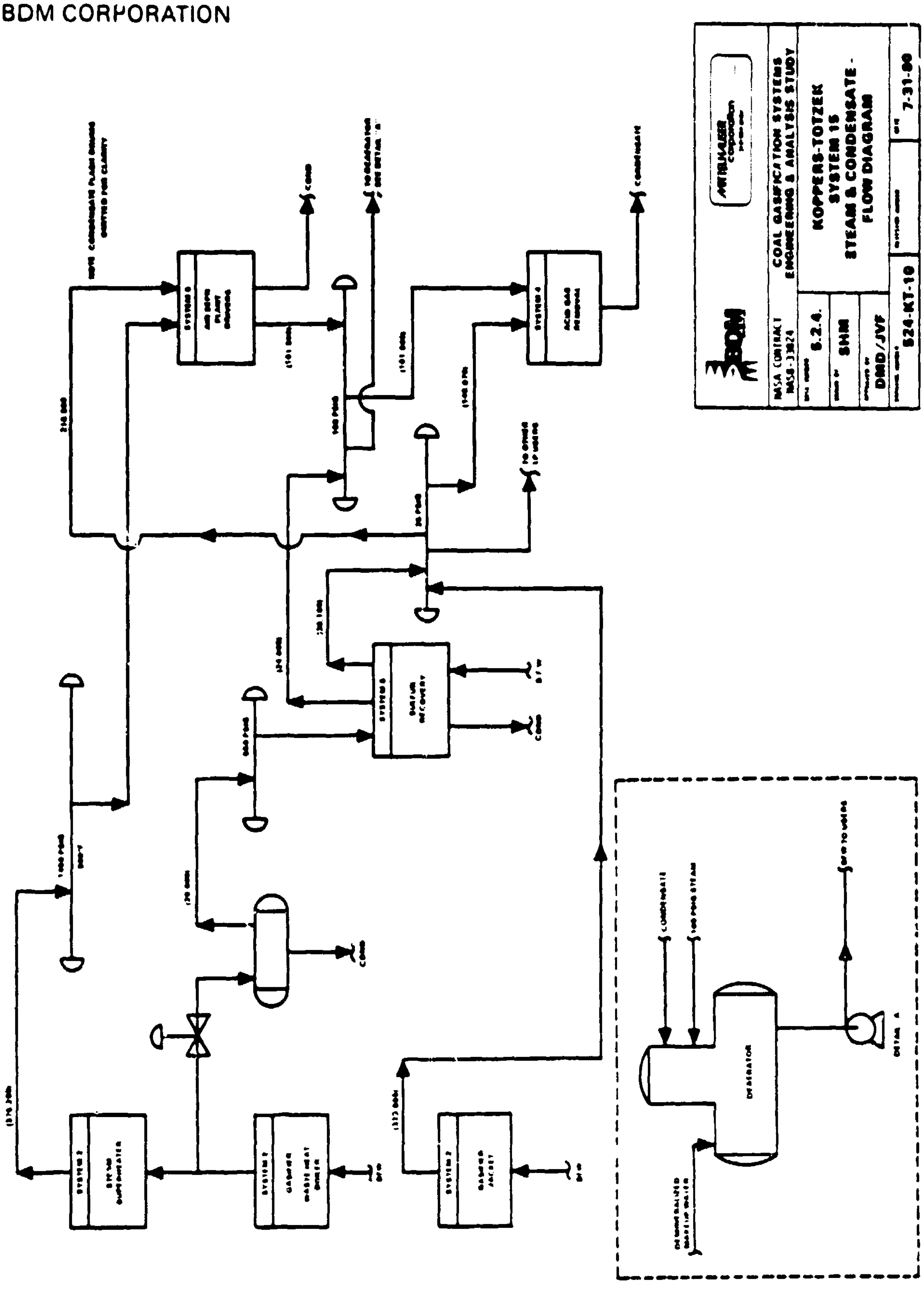
524-KT-06

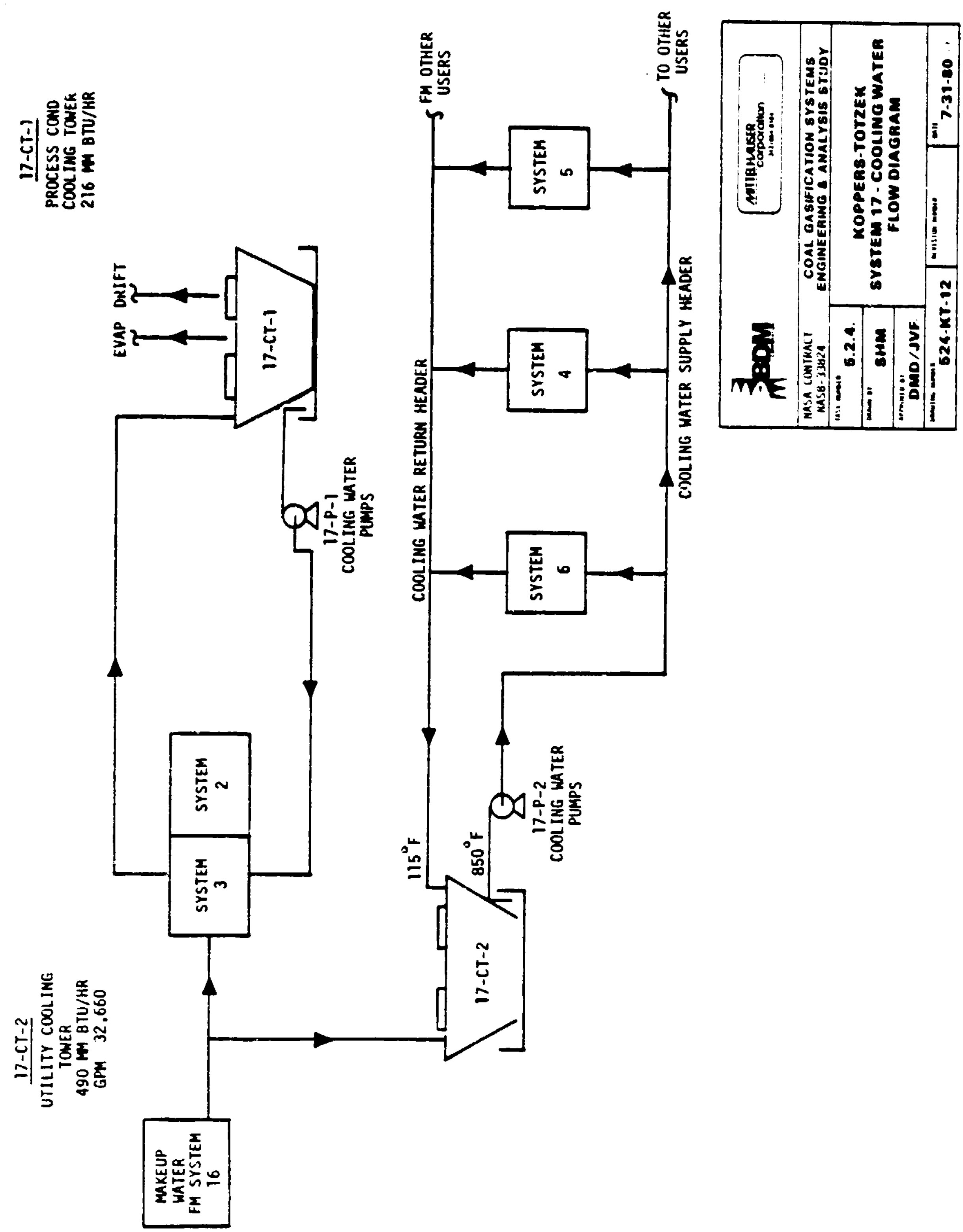
7-31-80

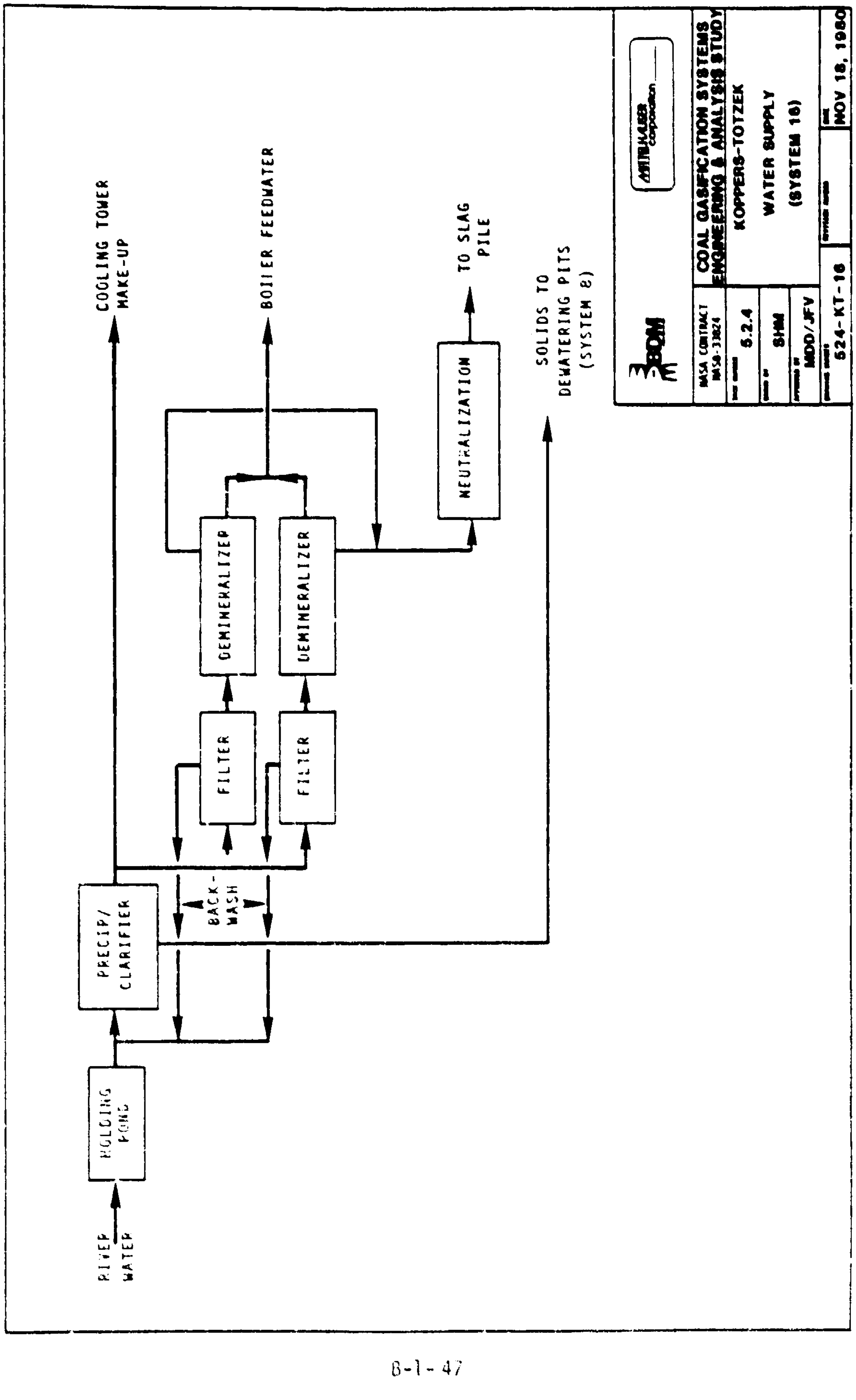

6-EA-1
AIR COOLER
66 MM BTU/HR
6-V-1
K.O. DRUM
6-EA-2
AIR COOLER
6-V-2
K.O. DRUM
6-C-3
OXYGEN
COMPRESSOR
CENTRIFUGAL
1750 HP
6-ME-1
AIR SEPARATION
PACKAGE
6-M-1
STARTUP MOTOR
DRIVE FOR C-1
6-C-1
AIR COMP
23,000 HP
AXIAL
6-ST-1
STEAM TURBINE
23,000 HP
EXTRACTION
(C-1 DRIVER)
6-M-2
STARTUP MOTOR
DRIVE FOR C-2
6-C-2
AIR COMP
7500 HP
CENTRIFUGAL
6-ST-2
STEAM TURBINE
LP CONDENSING
7500 HP
(C-2 DRIVER)
6-M-3
MOTOR DRIVER
VENT TO ATMOSPHERE
AIR
45 PSIA
370 F
6-EA-1
6-V-1
6-M-1
6-C-1
6-ST-1
6-M-2
6-C-2
6-EA-2
6-V-2
6-ST-2
PACKAGE
AIR SEP'N
UNIT
6-ME-1
NITROGEN
TO 2-E-1
DWG. NO. 524-KT-02
NITROGEN
TO 2-P-2
DWG. NO. 524-KT-02
OXYGEN
TO 2-R-1
DWG. NO. 524-KT-02
26 PSIG
77° F
HP
STEAM
1450 PSIG
900 F
MP
STEAM
150 PSIG
SAT'D
COND
LP
STEAM
26 PSIG
SAT'D
COND
6-C-3
6-M-3
BDM
NASA CONTRACT
NAS8-33824
COAL GASIFICATION SYSTEMS
ENGINEERING & ANALYSIS STUDY
5.2.4.
SHM
DMD/JVF
KOPPERS-TOTZEK
SYSTEM 6 - AIR SEPARATION
FLOW DIAGRAM
524-KT-06
7-31-80

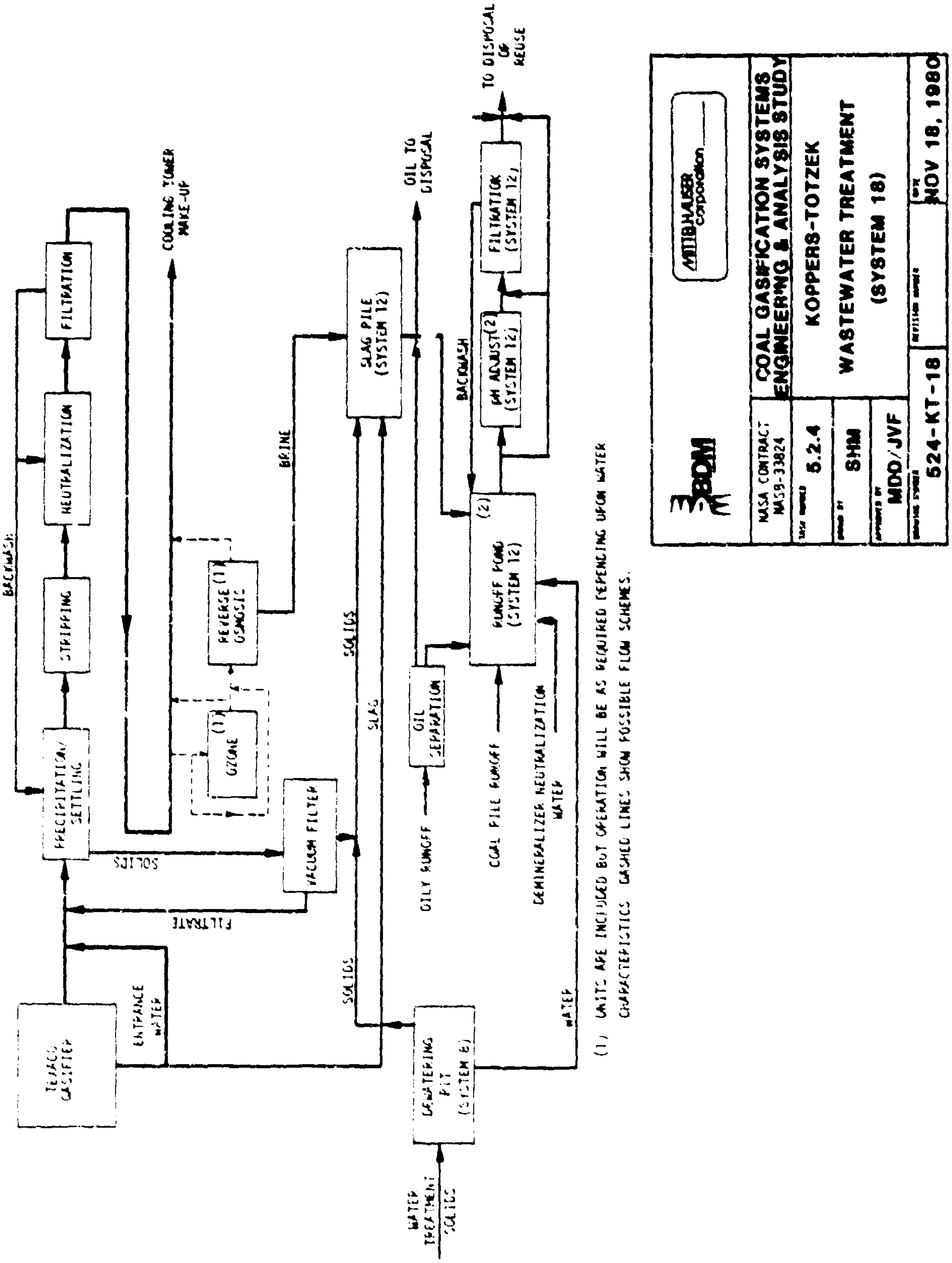

7 M 1
MOTORDRIVE
FOR 7 C 1A
7 M 2
MOTORDRIVE
FOR 7 C 1B
& 7 C 1C
7 C 1A
PDT GAS COMP
30 500 HP
AXIAL
7 C 1B
PDT GAS COMP
24,000 HP
CENTRIFUGAL
7 C 1C
PDT GAS COMP
21,300 HP
CENTRIFUGAL
7 EA 1
C 1A
AFTERCOOLER
7 EA 2A/B
C 1B
INTERCOOLERS
7 EA 3
C 1B
AFTERCOOLER
7 EA 4
C 1C
AFTERCOOLER
7 V 1
COMPRESSOR
KNOCK OUT
DRUM
7 V 2A & B
COMPRESSOR
KNOCK OUT
DRUM
7 V 3
COMPRESSOR
KNOCK OUT
DRUM
7 V 4
COMPRESSOR
KNOCK OUT
DRUM
RAW GAS
FROM
GAS COOLING
DWG. NO 524 KT 03
14.2 PSIA
100 F
68 PSIA
63 PSIA
130 F
270 PSIA
310
266 PSIA
130°F
860 PSIA
100°F
COND
GAS TO
ACID GAS
REMOVAL
DWG NO
524-KT 04
7 M 1
7 C 1A
7 M 2
7 C 1B
7 C 1C
7 E 1
7 V 4
7 EA 2A
7 EA 2B
7 V 2A
7 V 2B
BDM
MITTELHAUSER
corporation
NASA CONTRACT
NAS8-33824
COAL GASIFICATION SYSTEMS
ENGINEERING & ANALYSIS STUDY
5.2.4.
SHM
DMD/JVF
KOPPERS-TOTZEK
SYSTEM 7 - PRODUCT GAS
COMPRESSION FLOW DIAGRAM
524-KT-07
7-31-80


VENT TO ATMOSPHERE
RETURN
STEAM
LP COND
13-P-1
13-S-1
13-S-2
13-S-3
BLOWER 13-C-1
AIR
SULFUR FROM CLAUS SULFUR PLANT DWG NO 524 KT-08
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
SYSTEM 13 BY PRODUCT PROCESSING FLOW DIAGRAM
NASA CONTRACT NAS8-33824
6.2.4.
JVF
MOD/JVF
524 KT 08


NASA CONTRACT NAS8-33824
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
KOPPERS-TOTZEK SYSTEM 15 STEAM & CONDENSATE - FLOW DIAGRAM
5.2.4.
SHM
DMID/JVF
524-KT-10
7-31-80


17-CT-1
PROCESS COND
COOLING TOWER
216 MM BTU/HR
EVAP
DRIFT
17-CT-1
17-P-1
COOLING WATER
PUMPS
FM OTHER
USERS
TO OTHER
USERS
SYSTEM 5
SYSTEM 4
SYSTEM 6
COOLING WATER RETURN HEADER
COOLING WATER SUPPLY HEADER
SYSTEM 2
SYSTEM 3
115°F
850°F
17-P-2
COOLING WATER
PUMPS
17-CT-2
17-CT-2
UTILITY COOLING
TOWER
490 MM BTU/HR
GPM 32,660
MAKEUP
WATER
FM SYSTEM
16
NASA CONTRACT
NAS8-33824
6.2.4.
SHM
DMD/JVF.
524-KT-12
7-31-80
COAL GASIFICATION SYSTEMS
ENGINEERING & ANALYSIS STUDY
KOPPERS-TOTZEK
SYSTEM 17 - COOLING WATER
FLOW DIAGRAM


RIVER WATER
HOLDING POND
PRECIP/ CLARIFIER
BACK-WASH
FILTER
FILTER
DEMINERALIZER
DEMINERALIZER
NEUTRALIZATION
COOLING TOWER MAKE-UP
BOILER FEEDWATER
TO SLAG PILE
SOLIDS TO DEWATERING PITS (SYSTEM 8)
NASA CONTRACT NAS8-33824
5.2.4
SHM
MDD/JFV
524-KT-16
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
KOPPERS-TOTZEK
WATER SUPPLY
(SYSTEM 16)
NOV 18, 1980


TEXACO GASIFIER
ENTRANCE WATER
PRECIPITATION/ SETTLING
STRIPPING
NEUTRALIZATION
FILTRATION
BACKWASH
COOLING TOWER MAKE-UP
OZONE (1)
REVERSE OSMOSIS (1)
BRINE
SLAG PILE (SYSTEM 12)
OIL TO DISPOSAL
VACUUM FILTER
SOLIDS
FILTRATE
SLAG
SOLIDS
OIL SEPARATION
RUNOFF POND (SYSTEM 12) (2)
pH ADJUST (2) (SYSTEM 12)
FILTRATION (SYSTEM 12)
BACKWASH
TO DISPOSAL OR REUSE
OILY RUNOFF
COAL PILE RUNOFF
DEMINERALIZER NEUTRALIZATION WATER
WATER
DEWATERING PIT (SYSTEM 6)
WATER TREATMENT SOLIDS
(1) UNITS ARE INCLUDED BUT OPERATION WILL BE AS REQUIRED DEPENDING UPON WATER CHARACTERISTICS. DASHED LINES SHOW POSSIBLE FLOW SCHEMES.
BDM
NASA CONTRACT NAS8-33824
5.2.4
SHM
MDO/JVF
524-KT-18
MITTELHAUSER Corporation
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
KOPPERS-TOTZEK
WASTEWATER TREATMENT
(SYSTEM 18)
NOV 18, 1980

TVA MBG MODULE
KOPPERS-TOTZEK
SYSTEM NO. 1 COAL PREPARATION AND FEEDING

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
11-S-1	LIVE COAL SILO	0	4	SILO 11.750 TONS/ EACH
1-S-1	TRAMP IRON REMOVER	0	1	MAGNETIC
1-EV-1	LIVE COAL CONVEYOR	0	1	CONVEYOR
1-EV-2	WEIGH BELT CONVEYOR	0	1	SCALE AND CONVEYOR
1-BN-1	SIZED COAL STORAGE BIN	0	2	
1-S-2	PRIMARY CAOL CRUSHER	0	1	
1-CV-3	SIZED COAL CONVEYOR	0	1	CONVEYOR
1-S-3	RECYCLE SCREEN	0	1	

TVA MBG MODULE
KOPPER-TOTZEK
SYSTEM NO. 2 GASIFICATION

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
2-R-1	KOPPERS-TOTZEK GASIFIER	1	8	
2-P-1	RECIRCULATION BLOWER	9	8	
2-P-2	TRANSFER NITROGEN BLOWER	9	8	
2-P-3	CLARIFIER CIRCULATION PUMP	9	8	
2-P-4	SCRUBBER CIRCULATION PUMP	9	8	
2-F-1	TRANSPORT NITROGEN HEATER	1	8	
2-CV-1	CRUSHED COAL CONVEYOR	1	8	
2-BN-1	PULVERIZER SURGE BIN	1	8	
2- BN-2	PULIVERIZED COAL STORAGE BIN	1	8	

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
2- BN- 3	BUNKER STORAGE	1	8	
2- BN- 4	REACTOR FEED STORAGE	1	8	
2-CY-1	CYCLONES	2	16	
2-S-1	COAL PULIVERIZER	1	8	
2-S-2	SOLID PARTICLE RECOVERY	2	16	
2-ME 1,2	RAW GAS SCUBBERS	2	16	
2-ME-3	CLARIFIER	1	8	
3-T-1	RAW GAS COOLER	1	8	

TVA MBG MODULE
K-T GASIFIER
SYSTEM NO. 4 - ACID GAS REMOVAL

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
4-V-1	SOLVENT KNOCK-OUT DRUM	0	1	
4-V-2	SOLVENT FLASH DRUM	0	1	
4-V-3	REGENERATOR KNOCK-OUT	0	1	
4-T-1	ACID GAS ABSORBER	0	1	
4-T-2	SOLVENT REGENERATOR	0	1	
4-E-1	SOLVENT CHILLER	0	1	SHELL & TUBE EXCHANGER
4-E-2	SOLVENT COOLER	0	1	SHELL & TUBE EXCHANGER
4-E-3	REGENERATOR FEED PREHEAT EXCHANGER	0	1	SHELL & TUBE EXCHANGER
4-E-4	ACID GAS COOLER	0	1	AIR FAN EXCHANGER
4-E-5	REGENERATOR REBOILER	0	1	SHELL & TUBE EXCHANGER

TVA MBG MODULE
K-T GASIFIER
SYSTEM NO. 4 ACID GAS REMOVER

ITEM NUMBER	SERVICE	QUANTITY SPARE	QUANTITY OPERATION	DESCRIPTION
4-P-1	SOLVENT CIRCULATION PUMP	1	1	
4-P-2	REGENERATOR REFLEX PUMP	1	1	
4-P-3	SOLVENT TRANSFER PUMP	1	1	
4-TK-1	SOLVENT STORAGE TANK	0	1	
4-ME-1	TEG GAS DRYING PACKAGE	0	1	INCLUDES TEG CIRCULATION PUMP, TEG CONTRACTOR AND TEG REGENERATOR
4-C-1	RECYCLE VAPOR COMPRESSOR	0	1	
4-HT-1	RICH SOLVENT LET DOWN TURBINE	0	1	

TVA MBG MODULE
K-T GASIFIER
SYSTEM NO. 5 SULFUR RECOVERY & TAIL GAS CLEAN-UP

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
5-P-1	SULFUR PRODUCT PUMP	1	1	
5-P-2	STRETFORD SOUR WATER PUMP	1	1	
5-P-3	REDOX SOLUTION CIRCULATION PUMP	1	1	
5-P-4	STRETFORD SULFUR TRANSFER PUMP	1	1	
5-P-5	REACTION FURNACE AIR BLOWER	1	1	
5-S-1	AIR OXIDATION MIX TANK	0	1	
5-S-2	STRETFORD SULFUR SEPARATOR MELTOR	0	1	
5-S-3	MOLTER SULFUR STORAGE PIT	0	1	

TVA MBG MODULE
KOPPERS-TOTZEK
SYSTEM NO. 5 SULFUR RECOVERY & TAIL GAS CLEAN-UP

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
5-V-1	ACID GAS KNOCK - OUT DRUM	0	1	
5-R-1	REACTION FURNACE	0	1	ACID GAS BURNER AND STEAM GENERATION
5-R-2,3,4	SULFUR CONVERTERS	0	3	HORIZONTAL REACTORS
5-R-5	BEAVON HYDROTREATOR REACTOR	0	1	HORIZONTAL GAS HYDROLYSIS REACTOR
5-R-6	COMBUSTOR	0	1	HOT GAS GENERATOR
5-T-1	BEAVON UNIT CONTACT COOLER	0	1	
5-T-2	STRETFORD ABSORBER	0	1	
5-E-1,2,3,4	SULFUR CONDENSORS	0	4	SHELL & TUBE EXCHANGER
5-E-5	BEAVON UNIT GAS COOLER	0	1	SHELL & TUBE EXCHANGER

NOTE: THIS ENTIRE UNIT IS DUPLICATED IN MODULE 1 ONLY.

TVA MBG MODULE
KOPPERS-TOTZEK
SYSTEM NO. 5 SULFUR RECOVERY & TAIL GAS CLEAN-UP

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
5-E-6	STRETFORD RECYCLE COOLER	0	1	
5-P-1	LIQUID SULFUR PUMP	1	1	SUMP PUMP
5-P-2	SOUR WATER CIRCULATION PUMP	1	1	
5-P-3	REDOX SOLUTION CIRCULATION PUMP	1	1	
5-P-4	LIQUID SULFUR PUMP	1	1	
5-P-5	SULFUR SLURRY PUMP	1	1	MOYNO PUMP
5-ME-1	FILTER	0	1	SULFUR SLURRY FILTER

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
6-ME-1 A/B	AIR SEPARATION PLANT	0	2	PACKAGE SYSTEM 2052 TPD 95% O_2
6-C-1 A/B	AIR COMPRESSOR	0	2	AXIAL COMP. 23,000 H.P.
6-C-2 A/B	AIR COMPRESSOR	0	2	CENTRIFUGAL COMP. 7500 H.P.
6-C-3 A/B	O_2 COMPRESSOR	0	2	CENTRIFUGAL COMP. 1750 H.P.
6-ST-1 A/B	STEAM TURBINE DRIVER	0	2	DRIVER FOR C-1 CONDENSING/EXTRACTION H.P. TURBINE
6-ST-2 A/B	STEAM TURBINE DRIVER	0	2	DRIVER FOR C-2 CONDENSING L.P. TURBINE
6-M-1	ELECTRIC MOTOR	0	1	START-UP MOTOR FOR AIR PLANT C-1 COMP.
6-M-2	ELECTRIC MOTOR	0	1	START-UP MOTOR FOR AIR PLANT C-2 COMP.
6-M-3	ELECTRIC MOTOR	0	2	DRIVER FOR C-3

TVA MBG MODULE
KOPPERS-TOTZEK
SYSTEM NO. 6 - AIR SEPARATION

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
6-EA-1	AFTER COOLER	0	2	AIR COOLED EXGR. Q = 55 MMBTU/HR
6-EA-2	AFTER COOLER	0	2	AIR COOLED EXGR. Q = 55 MMBTU/HR
6-V-1	C-1 COMPR. K.O. DRUM	0	2	
6-V-2	C-2 COMPR. K.O. DRUM	0	2	

TVA MBG MODULE
KOPPERS-TOTZEK
SYSTEM NO. 7 - GAS COMPRESSION

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
7-C-1	PDT GAS COMPRESSOR	0	1	38,500 H.P. AXIAL MACHINE
7-C-2	PDT GAS COMPRESSOR	0	1	34,600 H.P. DOUBLE SUCTION CENTRIFUGAL
7-C-3	PDT GAS COMPRESSOR	0	1	21,300 H.P. CENTRIFUGAL
7-M-1	ELECTRIC MOTOR	0	1	DRIVER FOR C-1
7-M-2	ELECTRIC MOTOR	0	1	DRIVER FOR C-2 & C-3
7-EA-1	C-1 COMPRESSOR AFTERCOOLER	0	1	AIR COOLED HEAT EXCHANGER Q = 100 MMBTU/HR
7-EA-2	C-2 COMPRESSOR INTERCOOLER	0	2	AIR COOLED HEAT EXCHANGER Q = 48 MMBTU/HR
7-EA-3	C-2 COMPRESSOR AFTERCOOLER	0	1	AIR COOLED HEAT EXCHANGER Q = 43 MMBTU/HR
7-EA-4	C-3 COMPRESSOR	0	1	AIR COOLED HEAT EXCHANGER Q = 54 MMBTU/HR

TVA MBG MODULE
KOPPERS-TOTZEK
SYSTEM NO. 7 - GAS COMPRESSION

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
7-E-1	TRIM COOLER	0	1	SHELL & TUBE HEAT EXCHANGER Q = 6 MMBTU/HR
7-V-1	CONDENSATE K.O. DRUM	0	1	
7-V-2 A/B	CONDENSATE K.O. DRUM	0	2	
7-V-3	CONDENSATE K.O. DRUM	0	1	
7-V-4	CONDENSATE K.O. DRUM	0	1	

TVA MBG MODULE
KOPPERS-TOTZEK
SYSTEM NO. 13 - BY-PRODUCT PROCESSING

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
13-T-1	MOLTEN SULFUR STORAGE TANK	0	2	STEAM HEATED 500 TONS EACH
13-P-1	PRILL TOWER FEED PUMP	1	1	MOLTEN SULFUR PUMP
13-S-1	PRILLING TOWER	0	1	
13-S-2	PRILLED SULFUR CONVEYOR	0	1	
13-C-1	AIR BOILER	1	1	
13-S-3	PRILLED SULFUR STORAGE	0	1	5000 TONS STORAGE BUILDING

TVA MBG MODULE
KOPPERS-TOTZEK
SYSTEM NO. 17 - COOLING WATER

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
17-CT-1	PROCESS CONDENSATE COOLING TOWER	0	1	2 CELLS Q = 215 MMBTU/HR GPM BY K-T
17-CT-2	UTILITY COOLING TOWER	0	1	8 CELLS Q = 490 MMBTU/HR GPM = 32,660
17-P-1 A - E	COOLING WATER CIRCULATION PUMPS	1	4	
17-P-2 A - S	COOLING WATER CIRCULATION PUMPS	3	16	1,450 H.P.

TVA MBG MODULE
KOPPERS-TOTZEK
SYSTEM NO. 17 - COOLING WATER

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
17-CT-1	PROCESS CONDENSATE COOLING TOWER	0	1	2 CELLS Q = 215 MMBTU/HR GPM BY K-T
17-CT-2	UTILITY COOLING TOWER	0	1	8 CELLS Q = 490 MMBTU/HR GPM = 32,660
17-P-1 A - E	COOLING WATER CIRCULATION PUMPS	1	4	
17-P-2 A - S	COOLING WATER CIRCULATION PUMPS	3	16	1,450 H.P.

APPENDIX B-2

TEXACO COAL GASIFICATION PLANT
REFERENCE FACILITY DESIGN

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1.0 INTRODUCTION

The United States, after a number of years of development based on plentiful and inexpensive oil and natural gas, is entering a period of time when it is essential to supplement these energy sources by the increased use of coal. Coal is the nation's most plentiful fossil fuel. Coal gasification is a means of accomplishing this. While utilization of coal through conversion to gaseous products is not new there is no industry within the US which might serve as a base for establishing cost, operational reliability and requirements, and design data for the large scale environmentally acceptable plants needed.

The Tennessee Valley Authority with systems engineering and analysis support from the George C. Marshall Space Flight Center has initiated a project which would establish the commercial base and demonstrate the requirements for gasifying coal in a large integrated facility. The project consists of gasifying 20,000 tons per day of Eastern coal in a four module plant-the construction of which is staggered to accommodate efficient use of construction manpower and product market development.

The purpose of this study is the systematic engineering and cost analysis of five selected gasifier technologies and the other associated systems required to produce medium BTU gas for delivery into a 600 psig distribution system in Northern Alabama. This effort in a series of design studies provides a reference basis for selection of the final plant configuration and choice of process technologies.

The methodology consists of selection of a systematic breakdown of the facility for purpose of study, identification of available technologies for each system, development of a definition level design and cost analysis for each system, conducting a series of trade studies using the definition design as a basis, and finally development of reference facility designs and cost analyses based on the previous work.

This report covers the work done in establishing a Reference Facility Design based on Texaco coal gasification technology. It is one of three such designs, the other two being based on Babcock and Wilcox and Koppers-Totzek coal gasification processes. The design covers a complete grass roots facility site at Murphy Hill, Alabama. The plant inputs are coal, water and electricity. The plant outputs are medium BTU gas (MBG) and solidified sulfur.

The design approach involved breaking each of four identical modules into process and support systems followed by analysis of each system through identification of available technologies and use of the comparative trade studies to select the preferred processes for each system.

2.0 SUMMARY

A four module, 20,000 TPD, based on Texaco coal gasification technology has been designed. The plant processes Kentucky No. 9 coal with provisions for up to five percent North Alabama coal. Coal transportation is by river barge except for the Alabama coal which is trucked to the site. Medium BTU gas with heat content of 291 BTU/SCF and not more than 200 ppm sulfur is the primary plant product. Sulfur is recovered for sale as prilled sulfur. Ash disposal is on site. The plant is designed for zero water discharge. Trade studies provided the basis for not using boiler produced steam to drive prime movers. Thus process derived steam in excess of process requirements is superheated for power use in prime movers. Electricity from the TVA grid is used to supply the balance of the plant prime mover power requirements. A study of the effect of mine-mouth coal cleaning showed that coal cleaning is not an economically preferred route.

The plant design was arrived at by a systematic procedure based on published design work, process trade studies, team engineering experience, a NASA provided module level definition of some twenty systems, and the TVA document, "Design Criteria for Conceptual Designs and Assessments of TVA's Coal Gasification Demonstration Plant," March, 1980.

The overall plant configuration is shown schematically in Figure 2.1. As shown, General Facilities, Instrumentation and Control, and Coal Handling serve plant wide functions. All other plant components are contained in four identical process modules. The Instrumentation and Control System operates to monitor overall plant performance and to control intermodule relationships. The total list of systems is given in Table 2.1.

The design procedure involved defining available processes to meet the requirements of each system, technical/economic trade studies to select the preferred processes, and engineering design and flow sheet development for each module. Cost studies assumed a staggered construction schedule for the four modules beginning spring 1981 and a 90 percent on stream factor.

The basis and results of the design study are given in Tables 2.2 and 2.3.

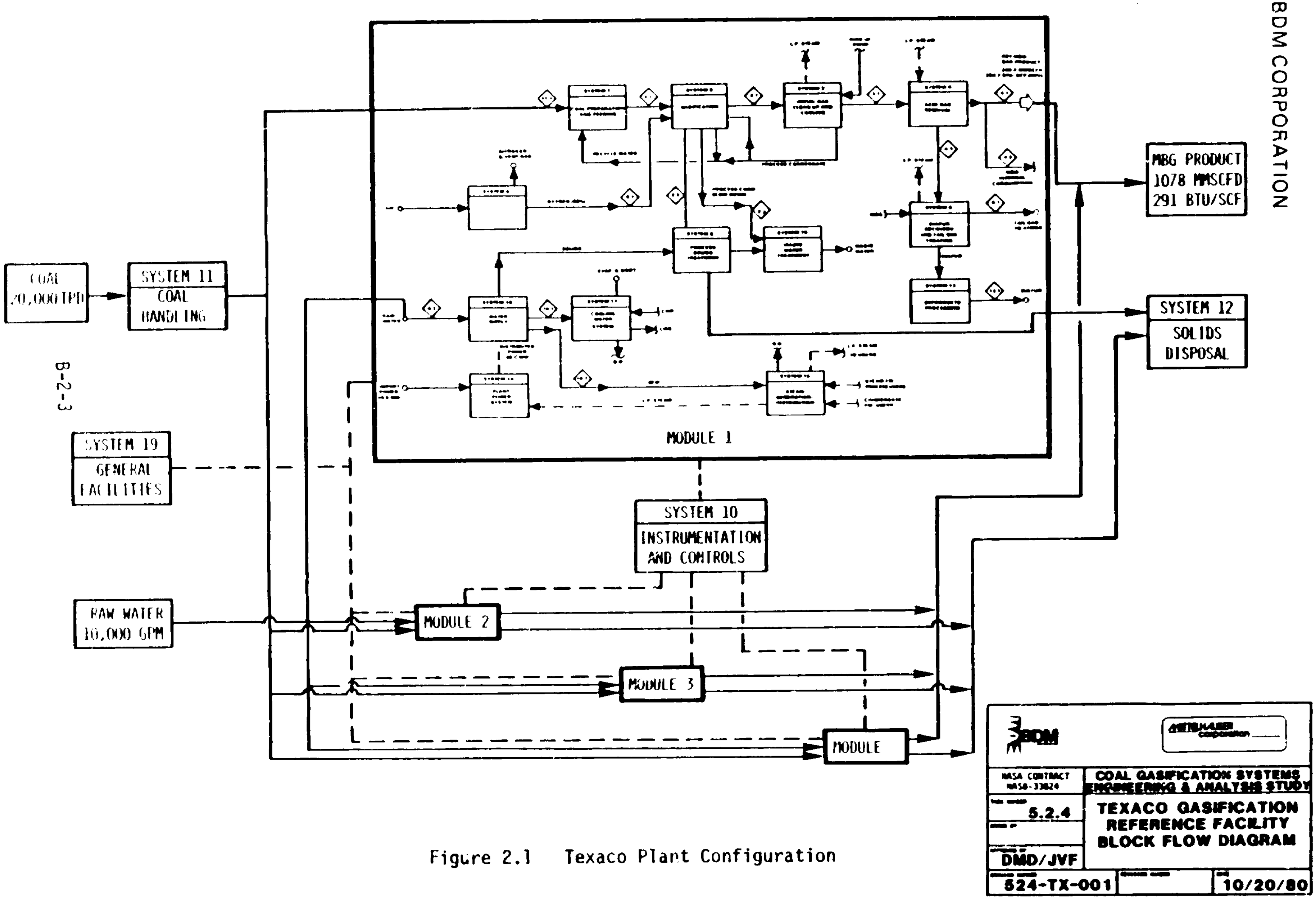


Figure 2.1 Texaco Plant Configuration

TABLE 2.1. LIST OF SYSTEMS

SYSTEM NO.	NUMBER OF PER MODULE	COST UNITS PER FACILITY	SYSTEM DESCRIPTION
1	1	4	COAL PREPARATION AND FEEDING
2	4	16	GASIFICATION
3	4	16	INITIAL GAS CLEANUP AND COOLING
4	1	4	ACID GAS REMOVAL
5	1	5	SULFUR RECOVERY
6	3	10	AIR SEPARATION
7	1	4	COMPRESSION
8	1	4	PROCESS SOLIDS TREATMENT
10	0	1	INSTRUMENTATION AND CONTROL
11	0	1	COAL HANDLING
12	0	1	SOLIDS DISPOSAL
13	1	4	BY-PRODUCT PROCESSING
14	1	4	PLANT POWER SYSTEM
15	1	4	STEAM GENERATION/DISTRIBUTION
16	1	4	RAW WATER MAKE-UP
17	1	4	COOLING WATER SYSTEM
18	1	4	WASTE WATER TREATMENT
19	0	1	GENERAL FACILITIES

TABLE 2.2. DESIGN BASIS SUMMARY*

PLANT CAPACITY	20,000 TPD
PLANT TYPE	FOUR INDEPENDENT MODULES
COAL TYPE	KENTUCKY NO. 9
PLANT SERVICE FACTOR	90 PER CENT
PLANT LIFE	20 YEARS EACH MODULE
ELECTRICITY SOURCE	TVA GRID-4.16KV, 6.9KV, 13.8KV
WATER	TENNESSEE RIVER
COAL RECEIPT	BARGE +5% BY TRUCK
PRODUCT DELIVERY	MBG AT 600 PSIG
PRODUCT QUALITY	MINIMUM 285 Btu/SCF
SULFUR	PRILLED
COAL COST (1980)	$1.25/MM Btu
LAND COST (1980)	$3,000/ACRE
CLEARING AND GRUBBING (1980)	$2,000/ACRE
ELECTRICITY COSTS (1980)	
BY-PRODUCT CREDIT	NONE
ESCALATION	AS PER TVA SPECIFICATION

*Design Criteria for Conceptual Designs and Assessments of TVA's Coal Gasification Demonstration Plant," Tennessee Valley Authority, March, 1980

TABLE 2.3. DESIGN STUDY RESULTS*

FEED COAL	6,570,000 TPY
WATER	10,000 GPM
PURCHASED ELECTRICITY	1,560 MM KWHY
MBG PRODUCT	1,078 M MSCFD
MBG PRODUCT	354 MM MSCFY
MBG QUALITY	291 BTU/SCF
SULFUR PRODUCT (PRILLED)	668 LTPD
SULFUR PRODUCT	222,000 LTPY
TOTAL CAPITAL REQUIREMENTS	$2,091 MM
OPERATING AND MAINTENANCE COSTS	$128 MM/YR
COAL, CATALYST, CHEMICALS	$181 MM/YR
PLANT OPERATING STAFF	271 PERSONS
MAINTENANCE/YEAR	$57 MM

* COSTS ARE IN 1980 DOLLARS

Designs in this study were based on published works, engineering experience and judgments, and consultations with appropriate process and equipment vendors followed by design calculations, flow process sheet development and documentation.

Cost estimates are based on normal conceptual level design estimating procedures as described in the "Coal Estimation and Economic Evaluation Methodology," BDM/W-80-258-TR-RV2, submitted as another part of this project work scope and reprinted as Appendix E. Schedule estimates are in accordance with overall guidelines furnished by NASA.

Details of the schedule are considered typical for projects of this type and while they do not represent a detailed analysis specific to this project they represent the complexity and illustrate schedule constraints associated with the subject project. Process flow diagrams are included for the main process systems, air separation system, cooling water system, and steam distribution system as aids in following written system descriptions.

Technical results of the study are reported in this appendix. A cost analysis is included as a part of Appendix D.

3.0 OVERALL FACILITY DESCRIPTION

This section presents and discusses the process design of a plant designed to gasify 20,000 tons per day of coal in four 5000 TPD modules and to produce a medium-Btu product fuel gas (MBG) with a higher heating value of 291 Btu/SCF. The plant design is based upon using entrained flow of gasifiers as offered by Texaco, and upon the design criteria (coal characteristics, product specifications, site data, etc.) set forth by the Tennessee Valley Authority in March, 1980.

3.1 O[illegible] Plant Processing

The overall plant configuration is shown in the block flow diagram, (see Figure 2.1). Kentucky No. 9 coal is received by barge and either placed in a dead storage pile or processed in System 11, Coal Handling. Provisions have also been made to receive up to five per cent of plant capacity by truck. Dead storage provides for 90 days interruption of supply.

Raw coal from System 11, Coal Handling, is ground and slurried with water. This slurry, containing 40 percent water, is pumped into three Texaco gasifiers per module operating at 690 psia pressure. The feed is partially combusted with oxygen from the air separation plant heating the mixture to approximately 2450°F. Ash becomes molten slag. Water contained in the feed is vaporized and reacts with the partial combustion products via the steam carbon and water gas shift reactions to produce a product rich in carbon monoxide and hydrogen. Raw gas is quenched within the reactor to 455°F. Molten slag is solidified in granules by the quenching operation and removed by lock hoppering along with quench water. After water-solids separation, the ash is disposed of on-site in a controlled disposal area. In the gas cooling and cleanup system, the gas is further cooled to 100°F before being treated in the acid gas removal system. The acid gas removal system uses the Selexol process (licensed by the Allied Chemical Corporation) in which a physical solvent (the dimethyl ether of polyethylene glycol) absorbs and removes hydrogen sulfide, carbonyl sulfide and the concomitant carbon dioxide from the raw gas.

The acid gas (hydrogen sulfide, carbonyl sulfide and carbon dioxide) is recovered from the Selexol solvent and processed in System 5, Sulfur Recovery and Tail Gas Treatment, wherein over 99 per cent of the hydrogen sulfide and carbonyl sulfide is converted into 668 long tons/day of by-product elemental sulfur. The sulfur recovery unit utilizes the conventional Claus process to convert about 90 to 95 per cent of the hydrogen sulfide (and some of the carbonyl sulfide) in the acid gas into by-product sulfur. The residual tail gas from the Claus unit is then processed in a Beavon-Stretford unit to recover additional by-product sulfur.

Oxygen utilized for the partial combustion of coal and recycle char in the gasifiers is produced in System 6, a conventional air separation plant. Atmospheric air is compressed to about 100 psia, cooled to 100°F and then separated cryogenically into oxygen and nitrogen at about 2 psig. The oxygen is compressed to about 815 psia for use in the gasifiers.

In addition to the systems contained in each module and described in Section 4, the plant consists of System 10, the overall plant monitoring and control system; System 11, the coal handling and storage system serving all four modules; and System 12, the solid waste disposal system serving the total facility.

The purpose of System 10 is to provide operational monitoring and supervisory master control of module operations. The system includes instrumentation to measure key characteristics of all major streams (mass, temperature, pressure, composition, density, and/or others as appropriate) and to display these characteristics in a central location. A dedicated computer is provided to record data of interest at the facility management level. Telecommunications capabilities are provided to communicate with module and systems operations as required to control total plant operation to meet delivery requirements.

System 11, the Coal Handling System, provides for the unloading of coal delivered to the plant either by barge or truck, reclaiming the coal from storage, reducing the size of coal, and transporting the coal to Coal Preparation and Feeding, System 1.

Raw coal is unloaded from barges by the barge unloading subsystem which is designed to unload up to ten 1500-ton capacity barges per shift. The coal is unloaded at an average rate of 1200 tons per hour on a five-day week basis. Coal is transferred by conveyor to a radial stacker which then produces a kidney-shaped coal pile containing live and dead storage. Coal is reclaimed from live storage and conveyed to a Bradford breaker where it is reduced in size to 2" x 0. Coal from trucks is unloaded into a chute from which it is conveyed to the Bradford breaker. Crushed coal from the Bradford breaker is transported to day storage silos from which it is transferred via vibrating belt conveyors to coal preparation and feeding, System 1, for further processing.

The purpose of System 12 is to store solid waste generated by facility operation during the facility life.

This system consists of a lined impounding pit sized to contain 20 years of solid waste. It includes the conveyor system to move the solids to the pit and a leachate recovery area to recover and pump leachate to the process condensate system.

Module descriptions are the subject of Section 4.

3.2 Facility Balances

The key material inputs and product outputs for the overall plant may be summarized as:

INPUTS:	Raw Coal	20,000 short tons/day
	98% Oxygen	17,080 short tons/day
	Raw Water Intake	10,000 gpm
	Imported Electric Power	198 MW
OUTPUTS:	Product Gas	1,178 MM SCFD
	By-product Sulfur	668 long tons/day
	Solids to Disposal (Wet)	3,312 tons/day
	Solids to Disposal (Dry)	3,305 tons/day

Table 3.1 gives the thermal efficiency for the facility. Table 3.2 gives the final product characteristics.

TABLE 3.1 CONVERSION EFFICIENCY TEXACO PROCESS
20,000 TPD FACILITY

	10^6 BTU/HR	PER CENT
INPUTS		
① COAL TO FACILITY	18,300	
② ELECTRIC POWER TO FACILITY	675.6	
OUTPUTS		
③ MBG FROM FACILITY	13,050.8	
④ COAL FINES FROM FACILITY	-0-	
EFFICIENCY		
COAL-TO MBG (③ ÷ ①) x 100%		71.3
OVERALL PRODUCT EFFICIENCY ③ ÷ (① + ②) x 100%		68.8
OVERALL FACILITY EFFICIENCY (③ + ④) ÷ (① + ②) x 100%		68.8

TABLE 3.2. PRODUCT CHARACTERISTICS

	VOLUME PER CENT
CARBON MONOXIDE	51.2
HYDROGEN	37.1
NITROGEN AND ARGON	1.3
CARBON DIOXIDE	9.9
METHANE	0.5
	100.0
HYDROGEN SULFIDE	48 PPM VOLUME
CARBONYL SULFIDE	161 PPM VOLUME
TOTAL SULFUR	209 PPM VOLUME
WATER VAPOR	7 LBS/MM SCF
HIGHER HEATING VALUE	291 BTU/SCF
TEMPERATURE	75 ^{o}F
PRESSURE	615 PSIA

4.0 MODULE DESCRIPTIONS

Each of the four modules in the plant consist of identical sequences of process systems as given in Table 2.1. Process flow diagrams and an equipment list are included in Section 5 for the principal process systems and such auxiliary systems, as cooling water and steam systems.

Each module receives 5000 TPD of coal from System 11, Coal Handling. The sequence of processing shown in Figure 4.1 is repeated in each of the four modules. Descriptions of each modular system are as follows.

4.1 System Descriptions

4.1.1 System 1 - Coal Preparation and Feeding

System 1, Coal Preparation and Feeding, receives 2"x0 coal feed from System 11, Coal Handling. Each module processes 5,000 TPD of ROM coal in one of two 100 percent units. This system, shown in Drawing Number 524-TX-01, grinds coal and produces a 60 wt percent coal slurry which is fed to System 2, Coal Gasification. This design is patterned after the Parson's design in EPRI report AF-880, "Preliminary Design Study for an Integrated Coal Gasification Combined Cycle Power Plant."

ROM coal is received by conveyor from storage silos and passed through a magnetic tramp iron remover. A prescreening system selects the 2"x1/4" coal for further size reduction in a cage mill. The combined cage mill product and minus 1/4" coal from the prescreening operation are further processed in a wet rod mill. The discharge from the rod mill containing approximately fifty percent water is diluted and screened to produce the desired size consistancy with oversized material being recycled to the mill. A centrifuge is used to reduce the water content of the coal slurry. Final water content is controlled at 40 percent by water addition to the centrifuge product in a mix tank. Final slurry control is obtained by density measurement in the mix tank pump around loop. The slurry feed is transferred to and maintained in two parallel agitated tanks prior to transfer to a run tank in System 2, Coal Gasification. Alternate use of the two parallel tanks allows precise control of slurry content before transferring to the next system.

4.1.2 System 2 - Coal Gasification

The Texaco Coal Gasification Process uses a coal slurry feed, consisting of fresh ground coal together with recycled fine slag and carbon with a total solids content of 60% by weight. The slurry is pumped from mix tanks in the grinding and slurry section to the gasifier slurry tank. A circulating pump circulates the slurry through this tank and supplies slurry to the suction of the high pressure charge pumps. The charge pumps raise the slurry pressure sufficient to feed the gasifiers at 690 psia.

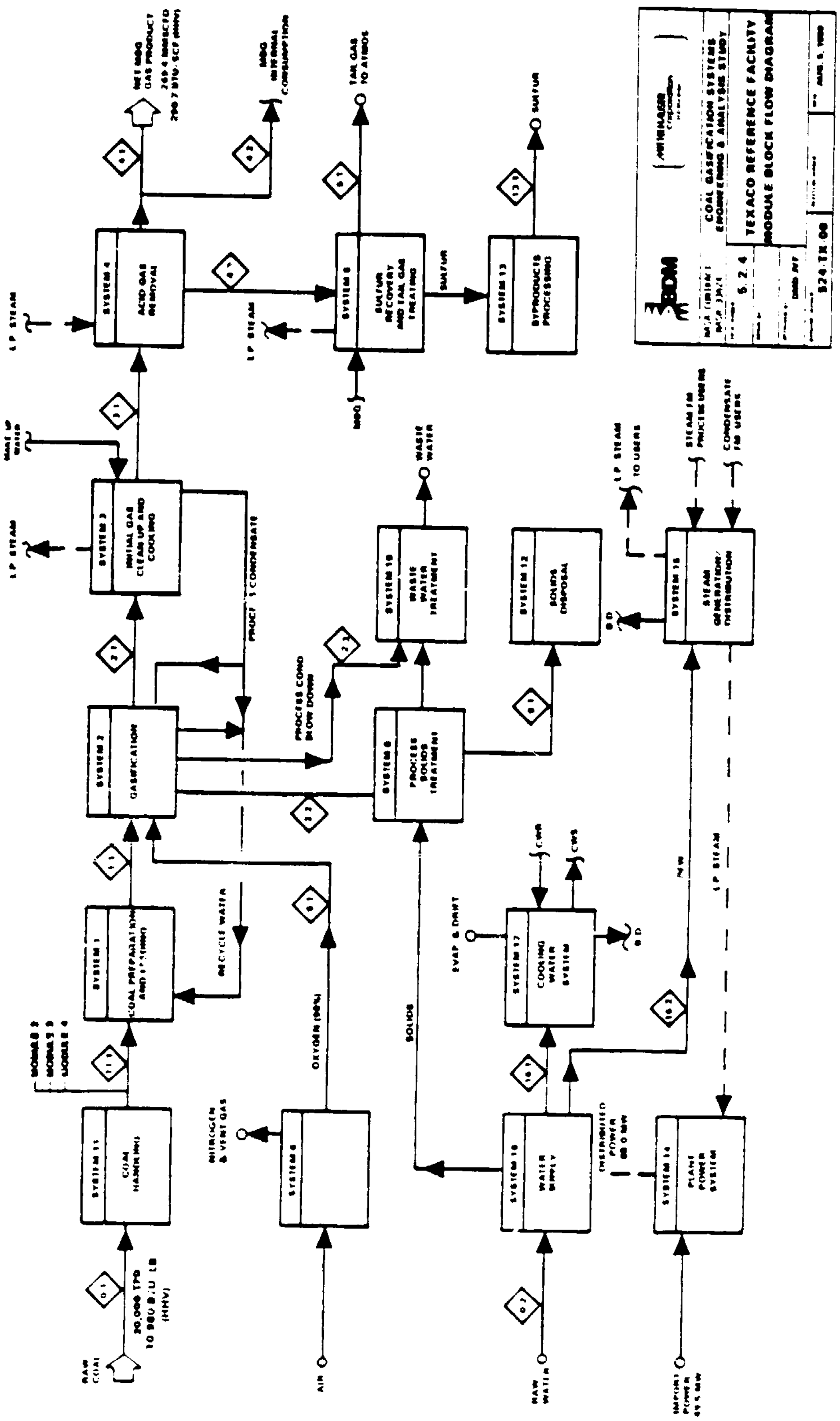

TEXACO REFERENCE FACILITY
MODULE BLOCK FLOW DIAGRAM
COAL GASIFICATION SYSTEMS
ENGINEERING & ANALYSIS STUDY
COAL HANDLING
COAL PREPARATION
GASIFICATION
INITIAL GAS CLEAN UP AND COOLING
ACID GAS REMOVAL
SULFUR RECOVERY AND TAIL GAS TREATING
BYPRODUCTS PROCESSING
PROCESS SOLIDS TREATMENT
WASTE WATER TREATMENT
SOLIDS DISPOSAL
STEAM GENERATION/DISTRIBUTION
COOLING WATER SYSTEM
WATER SUPPLY
PLANT POWER SYSTEM
RAW COAL
AIR
RAW WATER
OXYGEN
RECYCLE WATER
PROCESS COND BLOW DOWN
SOLIDS
SULFUR
TAIL GAS TO ATMOS
WASTE WATER
LP STEAM

Figure 4.1

The coal-water slurry is fed through a specially developed burner into a refractory-lined gasifier reactor. Partial combustion with oxygen takes place at a pressure of 675 psig, and a temperature of 2450 degrees F to produce a gas consisting mainly of CO, H_2, CO_2, and steam. Most of the sulfur in the coal is converted to H_2S with the balance converted to COS. Nitrogen and argon from the oxygen feed appear in the gas together with most of the nitrogen from the coal. The gas contains a small amount of methane. Some unconverted carbon and all of the ash are removed in the form of slag. The gas is essentially free of uncombined oxygen.

The upper section of the gasifier is the refractory-lined chamber in which the partial oxidation reaction takes place.

The gas from the gas generator reaction section passes straight down into the quench section of the gasifier along with the molten ash where it is immediately quenched with water from 2450 to 455 degrees F. Raw gas is sent to System 3, where residual carbon is scrubbed and the gas is further cooled.

Most of the ash in the coal feed agglomerates into essentially carbon-free molten slag droplets, which are quenched and solidified in the lower quench section of the reactor. This slag is settled through the quench water into the lock hopper. The lock hopper is periodically dumped onto a screen, from which the slag is conveyed to the solids treatment system.

Water from the gasifier quench chamber is cooled and combined with water from the carbon-scrubber lower section. Both streams contain fine slag and unconverted coal. The water stream from the lock hopper and water from the final product cooler separator join this stream, and the total flows into a flash pot.

Separation of water and solids takes in place in a clarifier where the fine slag and unconverted coal settle out, leaving a clarified water overflow that is pumped back to the carbon scrubber via a gray water drum. Makeup water is added at this point.

The clarifier underflow is fed to a centrifuge for dewatering. The concentrated underflow is returned to the coal grinding and slurrying section and mixed with coal-feed slurry. The filtrate is returned to the clarifier.

This system processes 5000 TPD of ROM coal in each plant module. Each module consists of three operating and one spare complete trains.

4.1.3 System 3 - Initial Gas Cleanup and Cooling

Raw gas at 675 psig and 455°F enter this system from the coal gasification system. The gas is cooled to 380°F in a steam generator producing 110 psig steam. Further cooling to 330°F in a second steam generator produces 50 psig steam. Boiler feed water to the steam generators is heated to 300°F by heat exchange with the gas from the second generator thereby lowering the gas temperature to 297°F. Water condensate is collected in knockout drums following each steam generator and heat exchanger and recycled for quenching in the gasification system. The gas is next processed in a Texaco proprietary scrubbing unit for recovery of soot from the gas stream. The soot-water blowdown from this unit is recycled to System 1, slurry preparation.

Following the gas scrubbing unit the gas is cooled by air coolers to 140°F. Water condensate is recycled to the gasification quench system and the gas scrubbing unit. The gas is further cooled to 105°F by exchange with cooling water and contacted with the system makeup water in an ammonia scrubber. Water from the ammonia scrubber is used as makeup in the coal slurry preparation unit. Product gas at 100°F and 625 psig is delivered to System 4, Acid Gas Removal. This system is given in Drawing Number 524-TX-03.

4.1.4 System 7 - Raw Gas Compression

The Texaco gasifiers operate at sufficient pressure to meet plant delivery requirements without product compression.

4.1.5 System 4 - Acid Gas Removal

The acid gas removal system utilizes the Selexol solvent process and received 721,825 lbs/hr of sour gas at 100°F and 640 psia. The sweet (desulfurized) gas leaves the Selexol absorber at about 630 psia and a temperature of 75°F. The component removals across the absorber are:

	Inlet Gas (mols/hr)	Outlet Gas (mols/hr)	% Removal
Methane	154	154	0.00
Hydrogen	11,038	11,032	0.02
Carbon monoxide	15,254	15,251	0.02
Carbon dioxide	5,467	2,938	46.26
Hydrogen sulfide	454	1	99.78
Carbonyl sulfide	29	5	86.21
Nitrogen	375	375	0.00
Water	48	4	91.67
	32,819	29,579	

The Selexol sulfur removal unit is a proprietary process licensed by Allied emical Company. The primary purpose of this system is to remove H_2S and COS from the product gas stream in order to obtain a sulfur concentration of not more than 200 ppmv. Secondarily, the process removes CO_2, which increases the gas heating value. System 4 is shown schematically in Drawing Number 524-TX-04.

The Selexol process removes sulfur compounds and carbon dioxide by means of countercurrent contact in an absorber. The physical absorption of the compounds to be removed is done using the dimethyl ether of polyethylene glycol as a solvent. Chilled solvent is used. Solvent chilling is accomplished by means of an absorption refrigeration system utilizing low pressure gasifier jacket steam.

CO_2 removal from the rich solvent leaving the absorber is accomplished by a series of successively lower pressure flashes. Flashed gas is recycled to the absorber inlet. Sulfur compounds are removed in the stripping column. The stripping column utilizes a steam heated reboiler. The stripper overhead gas, after cooling to about 120°F, flows to the sulfur recovery and tail gas treatment unit, System 5.

The sour gas from the Selexol unit is rich in CO_2, and at slightly above atmospheric pressure.

4.1.6 System 5 - Sulfur Recovery and Tail Gas Treatment

Acid gas from Acid Gas Removal, System 4, is fed to a Claus-type three-stage sulfur recovery unit utilizing a proprietary process for handling lean H_2S acid gases. Typically, in a Claus-type sulfur plant, the acid gas is first passed through a knockout drum before entering the reaction furnace. The chemistry of the process involves converting H_2S to elemental sulfur according to the following equation:

$$2H_2S + SO_2 \longrightarrow 3S + 2H_2O$$

The reactions are exothermic, and the heat liberated generates steam in the reaction furnace boiler and in the sulfur condenser. The sulfur from each condenser is drained to a recovery pit in By-Product Processing, System 13, and the tail gas from the final condenser is fed to a Beavon tail gas treating unit where essentially complete removal of the remaining sulfur compounds is achieved before discharge to the atmosphere. The Beavon sulfur removal process reduces the sulfur content in the tail gas to less than 100 ppm. In this system, hydrogenation and hydrolysis are used to convert essentially all sulfur compounds to hydrogen sulfide. This gas is then cooled and passed into a contactor where the hydrogen sulfide is absorbed by the redox solution and oxidized to elemental sulfur. The reduced redox solution is reoxidized by contact with air and subsequently recirculated to the contactor. Elemental sulfur is removed in the air-blowing step as a froth which is pumped to a sulfur melter to be melted under pressure, separated from the redox solution and transferred to By-Product Processing, System 13. The decanted redox solution is returned to the system. System 5 is shown in Drawing Number 524-TX-05.

The system receives 132,719 lbs/hr of acid gas from the Selexol solvent regenerator at about 7 psig and 120^{o}F.

The inlet gas composition is:

	Inlet Gas (mols/hr)
Hydrogen	4.5
Carbon monoxide	3.5
Carbon dioxide	2,529.2
Hydrogen sulfide	453.1
Carbonyl sulfide	24.4
Nitrogen	0.0
Water	244.1
	3,058.8

The recovery of by-product elemental sulfur from the sulfur recovery system is 167 long tons/day, which amounts to an overall sulfur recovery of about 99.9 percent.

4.1.7 System 6 - Air Separation

The purpose of this unit is to supply oxygen to the gasifiers. The process is non-proprietary and is offered in package form by several designer/manufacturers in the U. S. The gaseous oxygen stream of 98% purity is produced by distillation of liquified air. System 6 is shown schematically in Drawing Number 524-TX-06.

In the unit, which consists of multiple trains, 1,628,000 lbs/hr of atmospheric air is filtered and compressed to 110 psia by multi-stage compressors. Drivers are steam turbines with motors installed for start-up. The filtered-compressed air is cooled via cooled heat exchangers, then passes through reversing heat exchangers where it is cooled to slightly above its liquefaction temperature by heat exchange with the oxidant and waste gas streams, and by subsequent expansion through a turbine.

Water and carbon dioxide freeze out in the reversing exchangers, and are therefore removed from the inlet air stream. Subsequent switching of the exchanger sublimes the water and carbon dioxide into vapor which is vented as waste.

The cold air then enters the high pressure column for initial purification. The vapor at the top of the column is nitrogen containing 10 ppm of oxygen. Most of this is condensed in the high pressure condenser/low pressure reboiler and returned as reflux to the high pressure column. Some of this nitrogen vapor becomes the feed stream to the expansion turbine and some becomes low pressure product nitrogen gas after being superheated in the superheater and being warmed to about -150°F in a reversing heat exchanger.

Some of the nitrogen condensed in the condenser/reboiler becomes the liquid nitrogen product. It is first subcooled in the waste nitrogen core subcooler and then flashed into the liquid nitrogen separator. Liquid nitrogen product from the separator is transferred to the liquid nitrogen storage.

An impure reflux stream containing a small percentage of oxygen is withdrawn at an intermediate point in the column. It is subcooled and flashed into the top of the low pressure column.

The final purification of oxygen takes place in the low pressure column. The feeds to this column are impure reflux, and crude liquid oxygen from the high pressure column is subcooled and passed through the hydrocarbon absorbers before being flashed into the low pressure column. This procedures assures that all hydrocarbons are removed from the oxygen before purification. Processing the crude oxygen after it is liquified assures that the absorption is done at a relatively constant pressure and temperature and thus limits the possibility of accidental desorption.

As a further safeguard, a portion of the liquid oxygen in the low pressure sump is constantly withdrawn, passed through a guard hydrocarbon absorber and returned to the sump. This prevents trace quantities of hydrocarbons from accumulating in the low pressure sump.

The separated oxygen from the cold box (at 2 psig and 70^{O}F) is compressed, in six stages of compression, to 815 psia for use in the gasifiers.

Modules one and three have three trains each while modules two and four have two trains each of air separation.

4.1.8 System 8 - Process Solids Treatment

Approximately 69,003 pounds per hour per module of ash and slag from the gasifier and gas cooling system along with biological sludges and solid wastes from process condensate treatment are treated in this unit.

Gravity settlers separate dense solids from the waste streams.

Float thickeners-clarifiers treat slurry from the gravity settlers. Thickener and coagulant aids are added to facilitate solid-liquid separation.

Rotary drum filters filter sludges from the process condensate treating systems and the float thickeners.

Recovered water is sent to the process condensate treating system, and solids are conveyed to final solids disposal.

4.1.9 System 13 - By-Product Processing

Sulfur is the only plant by-product other than ash/char solids which are disposed of on-site. Molten sulfur is pumped to a prilling tower in a continuously flowing circulation system. In the tower, sulfur is dispensed in droplets through nozzles. Droplets fall counter current to a stream of cooling air and solidify prior to landing in the bottom prill collection section. From the prill tower, sulfur is conveyed to a storage building from which it is transferred by truck or barge for sale. System 13 is illustrated in Drawing Number 524-TX-13.

4.1.10 System 14 - Plant Power System

This system is generally designed to receive medium voltage electrical power (4.16 KV, 6.9 KV or 13.8 KV) and provide the following functions:

(1) Develop the necessary voltage stepdown arrangement for plant requirements

(2) Distribute the necessary power to the plant equipment.

TVA's incoming substation transformers receive power from its primary distributed voltage switching station and step down this voltage to a medium voltage to supply the plant electrical power requirement for motors, heaters, lighting, and other miscellaneous loads.

The Medium Voltage Electrical Distribution Systems is a secondary selection system (double ended supply) with several medium voltage buses. Each medium voltage bus receives power from its respective incoming substation transformer through an incoming breaker and supplies power to the medium voltage distribution system through the feeder breakers.

The Low Voltage Electrical Distribution System typically consists of multiple 480 V double-ended load centers and 480 V motor control centers (MCC's) supplying the power to 480 V loads throughout the plant. Two load centers are interconnected through a normally open tie breaker. In the event of loss of one load center transformer or its feeder, the 480 V loads of the affected load center are fed by the second load center through the tie breaker.

Each load center consists of an incoming line section, load center transformer, and low voltage section with metal enclosed draw out power circuit breakers.

Load center transformers are air cooled, dry type, 150°F temperature rise, with delta connected primaries and wye connected secondaries. All load center feeder circuit breakers are 1600A frame and 50,000A RMS symmetrical interrupting capacity. The 480 V motor feeder breakers are electrically operated with instantaneous and long time trip units.

480 V MCC's consist of starters, feeder circuit breakers and control devices, assembled in a common structure with horizontal and vertical buses.

A 125 volt DC system supplies control power for medium voltage and 480 volt plant switchgear control, protective relaying and annunciation. The system also supplies power for emergency lighting.

4.1.11 System 15 - Steam Generation/Distribution

In the absence of a waste heat boiler on the gasifier outlet there is no high pressure steam generated. Gas cooling and the sulfur plant provide 913,000 lb/hr of 125 psia saturated steam used as follows:

Selexol regenerator	-	240,000 lb/hr
Electric power generation	-	661,000 lb/hr
Turbine condensate reheat	-	12,000 lb/hr

Gas cooling and the sulfur plant produce 173,000 lb/hr of 65 psia saturated steam used as follows:

Selexol unit refrigeration	-	144,000 lb/hr
Sulfur heating	-	2,000 lbs/hr
Steam tracing	-	2,000 lbs/hr
BFW deaeration	-	25,000 lbs/hr

Steam condensate is recovered at 30 psia and 250°F. Total BFW circulation rate is 1,086,500 lbs/hr.

There are no fired steam boilers contained in the design. System 15 is shown in Drawing Number 524-TX-10.

4.1.12 System 16 - Water Supply

The raw water treatment unit is designed to provide treated and untreated water for the following facility water systems:

(1) Fire water
(2) Service water
(3) Potable water

(4) Cooling water
(5) Boiler feed water

Raw water is pumped from the river to a fire water-raw water storage tank.

The raw water-fire water storage tank provides surge capacity for water treatment as well as storage capacity for fire water. During an emergency, fire water is pumped from the tank to the fire water heater system. The fire water pumps are motor driven and have a diesel engine driven spare. The spare pump is equipped with automatic start-up capability in case of power failure.

The raw water is pumped from the raw water-fire water storage tank to the softener-clarifier. Lime, alum, and polyelectrolyte from the clarifier bulk chemical storage and feed system are added to the softener-clarifier, which is equipped with an internal flocculation mechanism. The alum and polyelectrolyte aid in the removal of suspended solids from the raw water. Lime is added during the clarification step to "cold soften" the raw water. Chlorine is added to the raw water to inhibit algae growth in the clarifier and sand filters and reduce organic contamination.

The underflow from the clarifier is a one wt percent sludge and is pumped to solids treatment for further processing.

The clarified and softened raw water from the softener-clarifier flows to the self-backwashing sand filters where additional suspended solids are removed. A pressure differential across the filter bed initiates the back-wash cycle. The backwash flows by gravity to the sand filter backwash sump and is recycled to the softener-clarifier. The filtered water flows to the filtered water storage tank and is utilized as cooling tower make-up for the process cooling tower as service water for general plant use, as feed to the demineralizer package, and as feed to the potable water system.

Water intended for potable services is chlorinated and again filtered to meet American Water Works Association (AWWA) standards and stored in a tank sized to hold a day's potable water requirements. The chlorine residual is maintained at 0.5-1.0 ppm free chlorine in the tank.

Filtered water intended as feed to the demineralizer package is injected with sodium sulfide to remove trace amounts of chlorine which adversely affect the demineralizer resins and after filtered through activated carbon to remove any remaining organic contaminants and dissolve iron.

In the demineralizer, the mineral salts present in the water are removed by ion exchange. A two-step demineralization system, utilizing strong cation and strong anion exchangers in series, is provided. A degasifier following the strong cation and magnesium, which the anion exchangers remove anions such as chloride and sulfate. The strong anion exchanger also removes silica. The degasifier is provided to remove carbon dioxide and other dissolved gases.

The mixed bed polisher is provided to remove silica to 0.02 ppm and to polish returned turbine condensate for reuse.

The boiler feed water deaerating heaters operate at 30 psig and 250^{o}F. The deaerators reduce the oxygen content of BFW to 0.005 cc/liter.

Hydrazine or sodium sulfite is injected into the storage compartment of the deaerators for chemical scavenging of any residual oxygen. Morpholine is injected into the suction of the boiler feed water pumps to protect the condensate systems.

The total water requirement is illustrated in Figure 4.2. Allowances for water treatment blowdown and contingency add to that shown to result in a total requirement of 2500 GPM per module.

Drawing Number 524-TX-16 shows System 16.

4.1.13 System 17 - Water Cooling

The purpose of this unit is to provide cooling water to the various process users in the facility.

The cooling tower system includes the tower and fans, side stream filters, circulating water pumps, cold water basin, blowdown system, chemical addition equipment, and distribution system.

Cooling water is pumped from the cold water basin, through the distribution system to the process heat exchangers where low-level, sensible heat is picked up, and back to the cooling tower. The cooling tower rejects low-level heat by evaporative cooling to air drawn through the cooling tower by the cooling tower fans.

A portion of the circulating water is passed through side stream filters to reduce loading to suspended solids, dirt and scale.

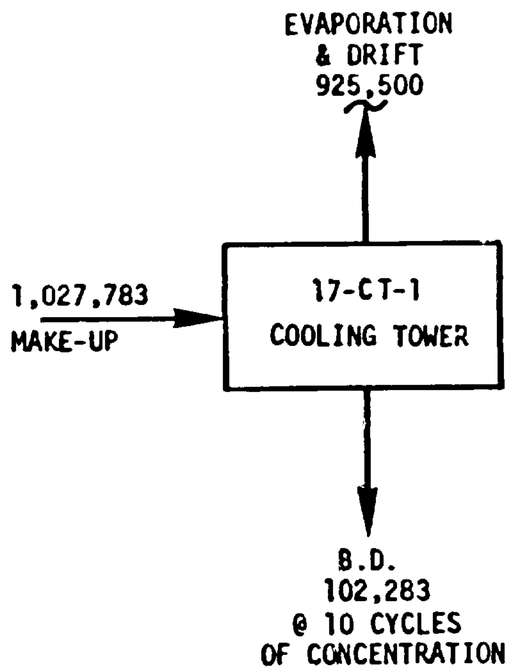
The dissolved solids level of the cooling water is maintained by a continuous blowdown stream to the process condensate system. Water level in the cooling tower basis is maintained by continuous make-up of the clean water from the raw water treatment system.

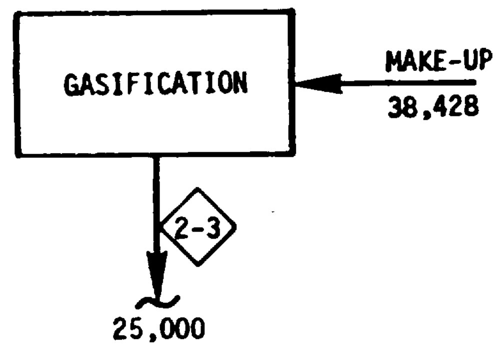
The blowdown stream is passed through a blowdown treatment system to recover chromate ions via ion exchange or by chemical reduction to chromium hydroxide and is sent to waste treatment for disposal.

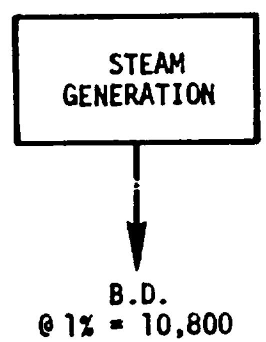
Chlorine is added to the cooling water on a routine periodic basis to prevent algae growth. Chemical algicides are added periodically to further

OVERALL WATER BALANCE (LBS/HR)

TEXACO







STEAM GENERATION

	110 PSIG	50 PSIG	TOTAL
SYSTEM 3	889,140	158,960	1,048,100
SYSTEM 8	24,000	14,400	38,400
			1,078,500

TOTAL WATER MAKE-UP

	LBS/HR		GPM
17-CT-1	1,027,783		
STEAM GEN.	10,800		
GASIFICATION	38,428		
	1,077,011		
ADD 5% FOR RAW WATER TREATMENT	53,850		
	1,130,861	LBS/HR	2262
W/10% CONTINGENCY			2500

Figure 4.2. Water Balance

eliminate algae growth. Sulfuric acid is added to control pH, and zinc and chromate inhibitors are added to the cooling water for corrosion control. Occasionally, a polyphosphate dispersant is added to enhance the action of the inhibitors. This system is illustrated in Drawing Number 524-TX-12.

4.1.14 System 18 - Waste Water Treatment

The purpose of this unit is to collect and treat all plant liquid effluent streams. The plant design is predicated on "zero discharge" and permits recycle and reuse of treated water. Streams treated include the following:

(1) Oily water sewers
(2) Coal pile run-off
(3) Storm water run-off
(4) Demineralizer regenerant wastes and rinse water
(5) Cooling tower blowdown
(6) Sanitary waste water
(7) Gasifier slag quench drains
(8) Separated water from solids treatment
(9) Filtrate from biological treatment.

Process operations include:

(1) Oil Separator - streams containing free and dissolved oil and treated in a gravity separator utilizing an emulsion breaking chemical and heat to separate the oil-water mixture

(2) Sour Water Stripper - water streams with appreciable H_2O and HN_3 residuals are steam-stripped to remove these contaminants

(3) Equalization Basin - liquid streams with extremely high or low pH are mixed in an equalizing basis and treated with sulfuric acid or caustic to change the mixed pH to a value of 6.0 - 8.0

(4) Gravity Settling-Thickener - liquid streams with high suspended or dissolved solids are treated in a gravity settler-thickener and mixed with lime, alum, coagulant aids, and polymers to facilitate separation and thickening

(5) Multiple Effect Evaporation - neutralized wastes and brines are evaporated to recover water and concentrate the solids.

The recovered, treated water is used as make-up to cooling towers or raw water supply. The resultant solids are conveyed to the solids disposal system. System 18 is illustrated in Drawing Number 524-TX-18.

4.1.15 System 19 - General Facilities

The purpose of this unit is to provide equipment or services to support the gasification facility at the facility level.

This unit is a general facility category and provides the following equipment and services:

(1) Administration building
(2) Laboratories
(3) Change rooms
(4) Warehouses
(5) Maintenance buildings
(6) Operation centers
(7) Security offices
(8) Plant air facility
(9) Fire house
(10) Visitor reception
(11) Plant fencing
(12) Plant lighting
(13) Roads, bridges
(14) Docking facilities
(15) Interconnection pipe ways
(16) Fire protection network
(17) Flare stacks and headers
(18) Plant instrument air compressors
(19) Environmental monitoring
(20) Site preparation.

4.2 Module Balances

Material and energy balances have been determined for each module. Table 4.1 gives stream compositions and quantities for each intersystem stream. Table 4.2 gives an energy balance at the modular level.

TABLE 4.1
MATERIAL BALANCE
TEXACO PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			0-1		0-2		1-1	
STREAM ID			COAL FEED		RAW WATER		COAL SLURRY TO GASIFICATION	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01		253,637		-		253,637
HYDROGEN	H_2	2.016		17,925		-		17,925
OXYGEN	O_2	32.0		23,901		-		23,901
NITROGEN & ARGON	N_2	28.016		5,761		-		5,761
SULFUR	S	32.06		15,449		-		15,449
CHLORINE	Cl	35.453		494		-		494
CARBON MONOXIDE	CO	28.01		-		-		-
CARBON DIOXIDE	CO_2	44.01		-		-		-
METHANE	CH_4	16.042		-		-		-
ETHYLENE	C_2H_4	28.052		-		-		-
ETHANE	C_2H_6	30.068		-		-		-
PROPYLENE	C_3H_6	42.078		-		-		-
PROPANE	C_3H_8	44.094		-		-		-
HYDROGEN SULFIDE	H_2S	34.076		-		-		-
CARBONYL SULFIDE	COS	60.075		-		-		-
CARBON DISULFIDE	CS_2	76.13		-		-		-
SULFUR DIOXIDE	SO_2	64.06		-		-		-
NITROUS OXIDE	NO	30.008		-		-		-
AMMONIA	NH_3	17.031		-		-		-
HYDROGEN CYANIDE	HCN	27.026		-		-		-
HYDROGEN CHLORIDE	HCl	36.461		-		-		-
NAPHTHA	-			-		-		-
TAR & OIL	-			-		-		-
ASH	-			59,650		-		59,650
OTHER SOLIDS				-		-		(A)
SUBTOTAL, DRY				376,817		-		376,817
WATER	H_2O	18.016		39,853		-		39,853
TOTAL, WET				416,670		-		416,670
GAS MOLECULAR WEIGHT				-		-		-
TEMPERATURE, °F				-		-		140
PRESSURE, PSIA				-		-		-
SCFH				-		-		-
GPM				-		2,533		-

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OF POOR QUALITY

MATERIAL BALANCE
TEXACO PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			2-1		2-2		2-3	
STREAM ID			RAW GAS TO COOLING		ASH FROM GASIFIER TO SOLIDS TREATMENT		PROCESS CONDENSATE BLOWDOWN	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01	-	-		-		-
HYDROGEN	H_2	2.016	11,037.5	22,252		-		-
OXYGEN	O_2	32.0	-	-		-		-
NITROGEN & ARGON	N_2	28.016	375.0	11,153		-		-
SULFUR	S	32.06	-	-		-		-
CHLORINE	Cl	35.453	-	-		-		-
CARBON MONOXIDE	CO	28.01	15,254.2	427,270		-		-
CARBON DIOXIDE	CO_2	44.01	5,466.7	240,589		-		-
METHANE	CH_4	16.042	154.2	2,474		-		-
ETHYLENE	C_2H_4	28.052	-	-		-		-
ETHANE	C_2H_6	30.068	-	-		-		-
PROPYLENE	C_3H_6	42.078	-	-		-		-
PROPANE	C_3H_8	44.094	-	-		-		-
HYDROGEN SULFIDE	H_2S	34.076	454.2	15,477		-		-
CARBONYL SULFIDE	COS	60.075	29.2	1,754		-		-
CARBON DISULFIDE	CS_2	76.13	-	-		-		-
SULFUR DIOXIDE	SO_2	64.06	-	-		-		-
NITROUS OXIDE	NO_2	30.008	-	-		-		-
AMMONIA	NH_3	17.031	104.2	1,775		-		-
HYDROGEN CYANIDE	HCN	27.026	-	-		-		-
HYDROGEN CHLORIDE	HCl	36.461	-	-		-		-
NAPHTHA	-		-	-		-		-
TAR & OIL	-		-	-		-		-
ASH	-		-	-		59,650		-
OTHER SOLIDS			-	-		2,577		-
SUBTOTAL, DRY			32,875.2	722,744		62,227		-
WATER	H_2O	18.016	66,543.9	1,198,855		*		25,000
TOTAL, WET			99,419.1	1,921,599		62,227		25,000
GAS MOLECULAR WEIGHT			19.33			-		-
TEMPERATURE, °F			455			-		-
PRESSURE, PSIA			690			-		-
SCFH			37,729,548			-		-
GPM			-			-		50

*Essentially no free water

MATERIAL BALANCE
TEXACO PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			3-1		4-1		4-2	
STREAM ID			COOLED GAS TO ACID GAS REMOVAL		NET MBG GAS PRODUCT		MBG INTERNAL CONSUMPTION	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01	-	-	-	-	-	-
HYDROGEN	H_2	2.016	11,037.5	22,252	10,965.8	22,107.5	67.2	135.5
OXYGEN	O_2	32.0	-	-	-	-	-	-
NITROGEN & ARGON	N_2	28.016	375.0	11,153	372.72	11,085.0	2.28	67.8
SULFUR	S	32.06	-	-	-	-	-	-
CHLORINE	Cl	35.453	-	-	-	-	-	-
CARBON MONOXIDE	CO	28.01	15,254.2	427,270	15,157.8	424,567.0	32.9	2,602.1
CARBON DIOXIDE	CO_2	44.01	5,466.7	240,589	2,919.6	128,491.6	17.9	787.8
METHANE	CH_4	16.042	154.2	2,474	153.26	2,458.6	0.94	15.1
ETHYLENE	C_2H_4	28.052	-	-	-	-	-	-
ETHANE	C_2H_6	30.068	-	-	-	-	-	-
PROPYLENE	C_3H_6	42.078	-	-	-	-	-	-
PROPANE	C_3H_8	44.094	-	-	-	-	-	-
HYDROGEN SULFIDE	H_2S	34.076	454.2	15,477	1.444	39.0	0.006	0.204
CARBONYL SULFIDE	COS	60.075	29.2	1,754	4.771	286.6	0.029	1.742
CARBON DISULFIDE	CS_2	76.13	-	-	-	-	-	-
SULFUR DIOXIDE	SO_2	64.06	-	-	-	-	-	-
NITROUS OXIDE	NO	30.008	-	-	-	-	-	-
AMMONIA	NH_3	17.031	-	-	-	-	-	-
HYDROGEN CYANIDE	HCN	27.026	-	-	-	-	-	-
HYDROGEN CHLORIDE	HCl	36.461	-	-	-	-	-	-
NAPHTHA	-		-	-	-	-	-	-
TAR & OIL	-		-	-	-	-	-	-
ASH	-		-	-	-	-	-	-
OTHER SOLIDS			-	-	-	-	-	-
SUBTOTAL, DRY			32,771.0	720,969	29,575.095	589,035.3	181.255	3,610.246
WATER	H_2O	18.016	47.5	856	4.36	78.5	0.067	1.207
TOTAL, WET			32,818.5	721,825	29,579.455	589,113.8	181.322	3,611.453
GAS MOLECULAR WEIGHT			21.99		19.92		19.92	
TEMPERATURE, °F			100		60		57	
PRESSURE, PSIA			640		615		615	
SCFH			12,454,621		11,225,403		68,812	
GPM	-		-		-		-	

MATERIAL BALANCE
TEXACO PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			4-3		5-1		6-1	
STREAM ID			ACID GAS TO SULFUR RECOVERY		TAIL GAS FROM SULFUR RECOVERY		OXYGEN TO GASIFICATION	
	SYMBOL	FORMULA WEIGHT	LB-MOLS / HR	LBS / HR	LB-MOLS / HR	LBS / HR	LB-MOLS / HR	LBS / HR
CARBON	C	12.01	-	-	-	-	-	-
HYDROGEN	H_2	2.016	4.5	9.1	25.8	52	-	-
OXYGEN	O_2	32.0	-	-	-	-	10,906	349,008
NITROGEN & ARGON	N_2	28.016	-	-	1,000.7	28,036	220.2	6,825
SULFUR	S	32.06	-	-	-	-	-	-
CHLORINE	Cl	35.453	-	-	-	-	-	-
CARBON MONOXIDE	CO	28.01	3.5	98.0	-	-	-	-
CARBON DIOXIDE	CO_2	44.01	2,529.2	111,310.1	2,587.4	113,871	-	-
METHANE	CH_4	16.042	-	-	-	-	-	-
ETHYLENE	C_2H_4	28.052	-	-	-	-	-	-
ETHANE	C_2H_6	30.068	-	-	-	-	-	-
PROPYLENE	C_3H_6	42.078	-	-	-	-	-	-
PROPANE	C_3H_8	44.094	-	-	-	-	-	-
HYDROGEN SULFIDE	H_2S	34.076	453.05	15,438.1	0.00279	0.095	-	-
CARBONYL SULFIDE	COS	60.075	24.4	1,46	-	-	-	-
CARBON DISULFIDE	CS_2	76.13	-	-	-	-	-	-
SULFUR DIOXIDE	SO_2	64.06	-	-	-	-	-	-
NITROUS OXIDE	NO	30.008	-	-	-	-	-	-
AMMONIA	NH_3	17.031	-	-	-	-	-	-
HYDROGEN CYANIDE	HCN	27.026	-	-	-	-	-	-
HYDROGEN CHLORIDE	HCl	36.461	-	-	-	-	-	-
NAPHTHA	-		-	-	-	-	-	-
TAR & OIL	-		-	-	-	-	-	-
ASH	-		-	-	-	-	-	-
OTHER SOLIDS			-	-	-	-	-	-
SUBTOTAL, DRY			3,014.65	128,321.1	3,613.9	141,959	11,126	355,833
WATER	H_2O	18.016	244.1	4,397.7	167.9	3,025	-	-
TOTAL, WET			3,258.75	132,718.8	3,781.8	144,984	11,126	355,833
GAS MOLECULAR WEIGHT			40.73		38.34		31.98	
TEMPERATURE, °F			120		100		300	
PRESSURE, PSIA			22		14.6		815	
SCFH			1,236,696		1,435,193		4,228,146	
GPM			-		-		-	

MATERIAL BALANCE
TEXACO PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			8-1		11-1		13-1	
STREAM ID			PROCESS SOLIDS TO DISPOSAL		COAL TO COAL PREPARATION		BY-PRODUCT SULFUR	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01		-		253,637	-	-
HYDROGEN	H_2	2.016		-		17,925	-	-
OXYGEN	O_2	32.0		-		23,901	-	-
NITROGEN & ARGON	N_2	28.016		-		5,761	-	-
SULFUR	S	32.06		-		15,449	477.4	15,305
CHLORINE	Cl	35.453		-		494	-	-
CARBON MONOXIDE	CO	28.01		-		-	-	-
CARBON DIOXIDE	CO_2	44.01		-		-	-	-
METHANE	CH_4	16.042		-		-	-	-
ETHYLENE	C_2H_4	28.052		-		-	-	-
ETHANE	C_2H_6	30.068		-		-	-	-
PROPYLENE	C_3H_6	42.078		-		-	-	-
PROPANE	C_3H_8	44.094		-		-	-	-
HYDROGEN SULFIDE	H_2S	34.076		-		-	-	-
CARBONYL SULFIDE	COS	60.075		-		-	-	-
CARBON DISULFIDE	CS_2	76.13		-		-	-	-
SULFUR DIOXIDE	SO_2	64.06		-		-	-	-
NITROUS OXIDE	NO	30.008		-		-	-	-
AMMONIA	NH_3	17.031		-		-	-	-
HYDROGEN CYANIDE	HCN	27.026		-		-	-	-
HYDROGEN CHLORIDE	HCl	36.461		-		-	-	-
NAPHTHA	-			-		-	-	-
TAR & OIL	-			-		-	-	-
ASH	-			59,650		59,650	-	-
OTHER SOLIDS				3,203		-	-	-
SUBTOTAL, DRY				68,853		376,817	477.4	15,305
WATER	H_2O	18.016		150		39,853	-	-
TOTAL, WET				69,003		416,670	477.4	15,305
GAS MOLECULAR WEIGHT				-		-	-	-
TEMPERATURE, °F				-		-	-	-
PRESSURE, PSIA				-		-	-	-
SCFH				-		-	-	-
GPM								

MATERIAL BALANCE
TEXACO PROCESS
I[illegible]GRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			16-1		16-2			
STREAM ID			MAKE-UP WATER TO COOLING TOWER		MAKE-UP WATER TO STEAM GENERATORS			
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01						
HYDROGEN	H_2	2.016						
OXYGEN	O_2	32.0						
NITROGEN & ARGON	N_2	28.016						
SULFUR	S	32.06						
CHLORINE	Cl	35.453						
CARBON MONOXIDE	CO	28.01						
CARBON DIOXIDE	CO_2	44.01						
METHANE	CH_4	16.042						
ETHYLENE	C_2H_4	28.052						
ETHANE	C_2H_6	30.068						
PROPYLENE	C_3H_6	42.078						
PROPANE	C_3H_8	44.094						
HYDROGEN SULFIDE	H_2S	34.076						
CARBONYL SULFIDE	COS	60.075						
CARBON DISULFIDE	CS_2	76.13						
SULFUR DIOXIDE	SO_2	64.06						
NITROUS OXIDE	NO	30.008						
AMMONIA	NH_3	17.031						
HYDROGEN CYANIDE	HCN	27.026						
HYDROGEN CHLORIDE	HCl	36.461						
NAPHTHA	-							
TAR & OIL	-							
ASH	-							
OTHER SOLIDS								
SUBTOTAL, DRY								
WATER	H_2O	18.016						
TOTAL, WET								
GAS MOLECULAR WEIGHT			-		-			
TEMPERATURE, °F			-		-			
PRESSURE, PSIA			-		-			
SCFH			-		-			
GPM			1,850		22			

TABLE 4.2

ENERGY BALANCE, 10^6 BTU PER HOUR
TEXACO PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

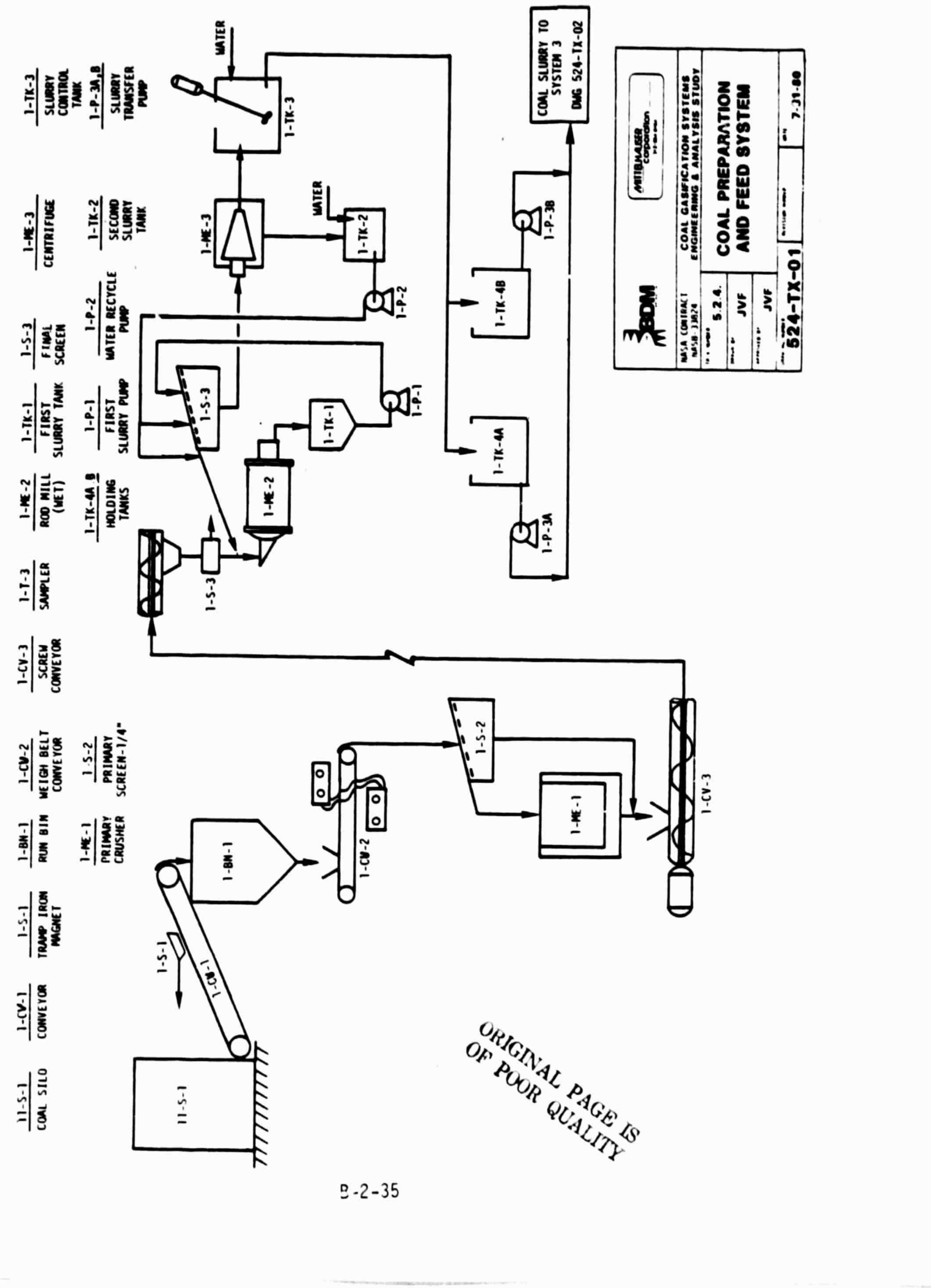
ENTHALPY BALANCE		PHASE	HHV	LATENT	SENSIBLE	TOTAL
INLETS						
STREAM	Coal	Solid	4575		0	4575
	Air to Air Sep'n	Gas		14	0	14
	Raw Water	Liquid				0
SUBTOTAL IN						4589
OUTLETS						
STREAM	MBG	Gas	3262.7		0	3262.7
	Ash	Solid	30.4		8.0	38.4
	Tail Gas	Gas		3.2	1.5	4.7
	Sulfur	Solid	57.7		0	57.7
	Air Sep'n Vent	Gas		8.1	9.6	17.7
	Flue Gases	Gas				
SUBTOTAL OUT						3381.2
NET INLET-OUTLET						1207.8
HEAT AND SHAFT WORK						
ELECTRIC POWER						168.9
SHAFT WORK						0
HEAT REJECTION				-750.1	-551.0	-1301.1
HEAT INPUT (STEAM)						0
RADIATION/FUGITIVE LOSS						-42.4
SUBTOTAL NET VALUE						-1174.6
TOTAL ABSOLUTE VALUE						1174.6

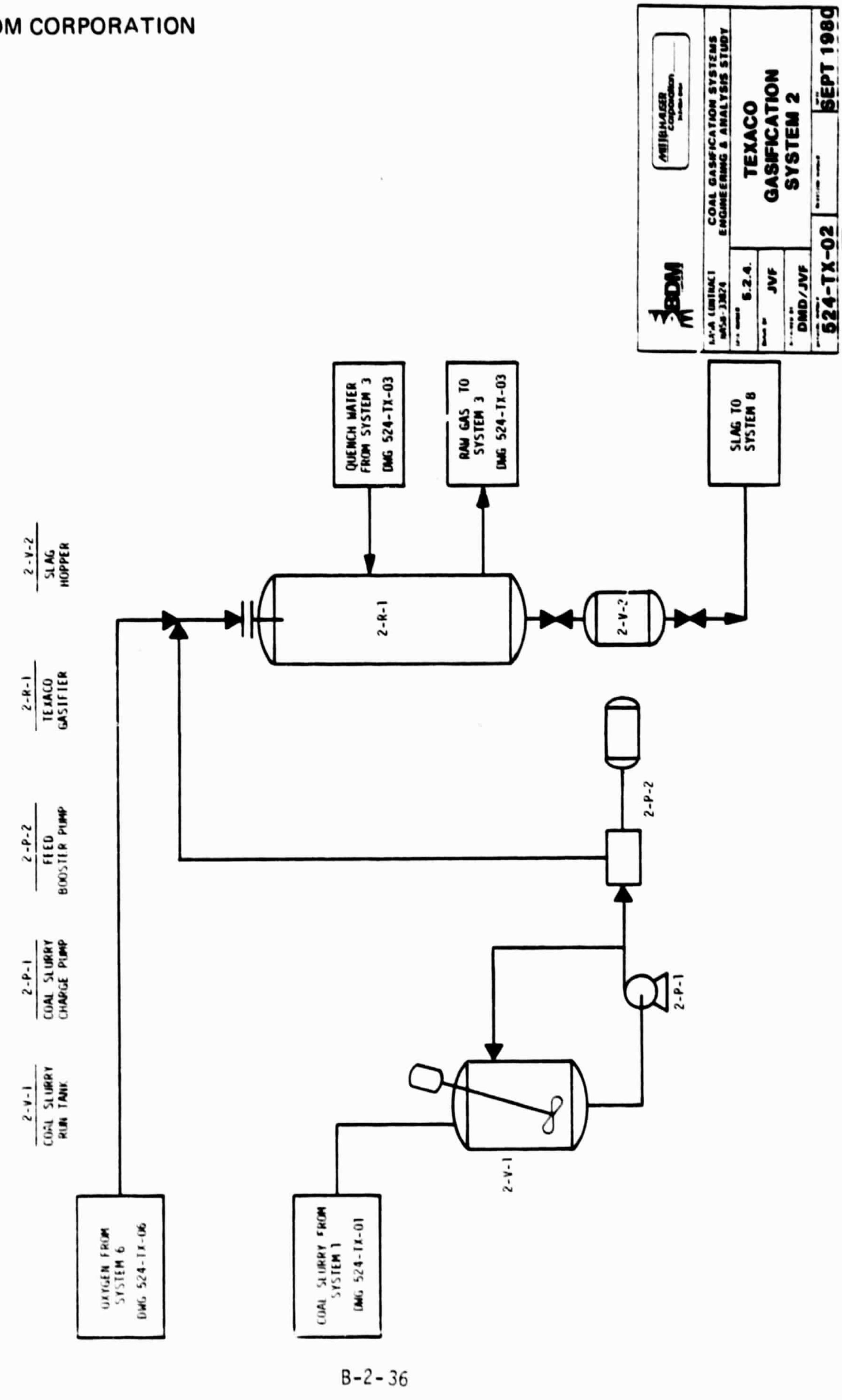
BALANCE: $\dfrac{\text{NET ENTHALPY + NET HEAT \& SHAFT WORK}}{\text{TOTAL ABSOLUTE VALUE OF HEAT \& SHAFT WORK}} \times 100\% = 2.8\%$

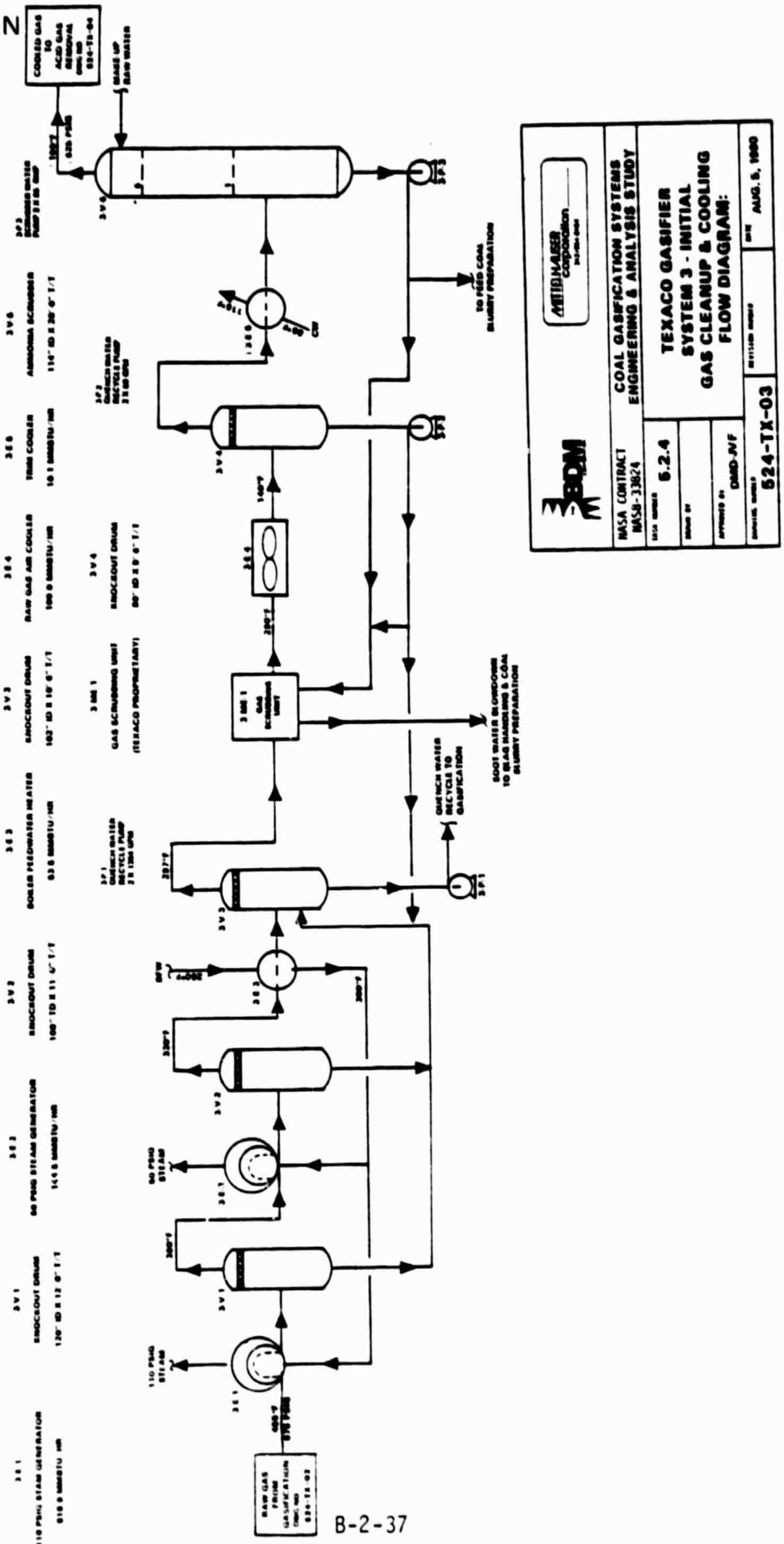
BASIS: $60^{o}F$; LIQUID WATER

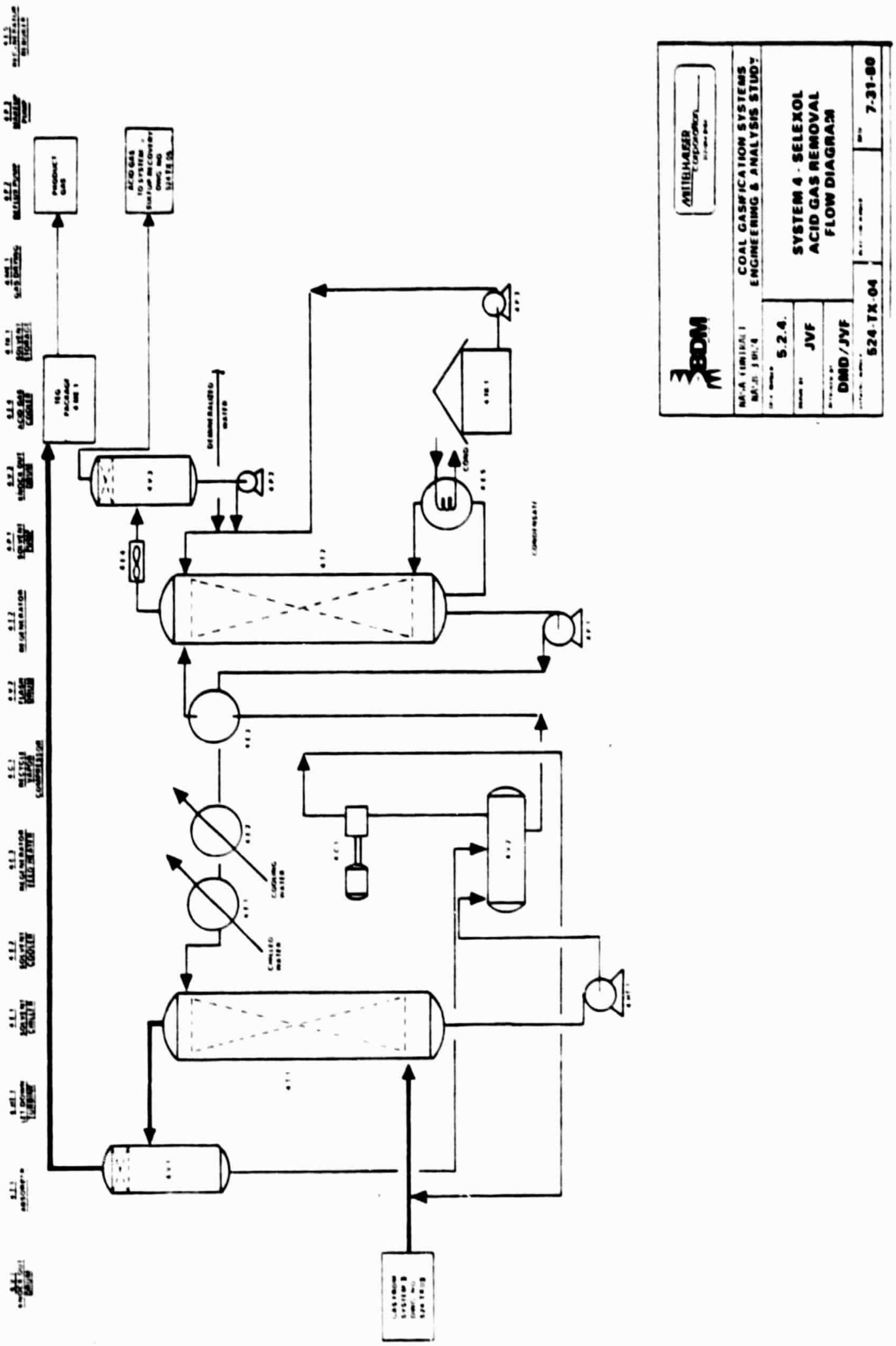
5.0 PROCESS FLOW DIAGRAM AND EQUIPMENT LIST

This section contains the process flow diagrams and the list of equipment for each module. The facility contains four times the quantity shown here except for the coal silos which are on a facility basis and System 5, which has two trains in Module 1 and only one train in subsequent modules.

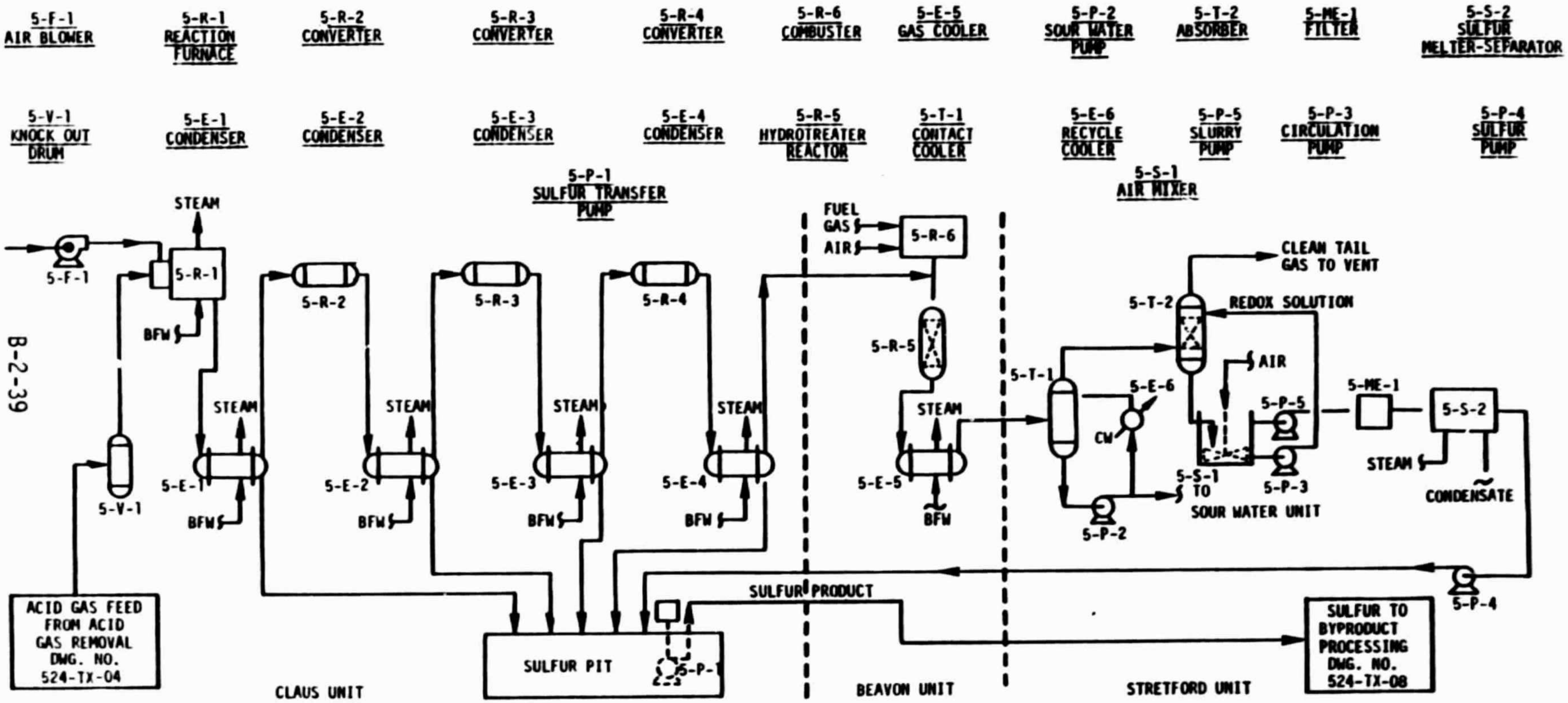

11-S-1 COAL SILO
1-CV-1 CONVEYOR
1-S-1 TRAMP IRON MAGNET
1-BN-1 RUN BIN
1-ME-1 PRIMARY CRUSHER
1-CV-2 WEIGH BELT CONVEYOR
1-S-2 PRIMARY SCREEN-1/4"
1-CV-3 SCREW CONVEYOR
1-T-3 SAMPLER
1-ME-2 ROD MILL (WET)
1-TK-4A,B HOLDING TANKS
1-TK-1 FIRST SLURRY TANK
1-P-1 FIRST SLURRY PUMP
1-S-3 FINAL SCREEN
1-P-2 WATER RECYCLE PUMP
1-ME-3 CENTRIFUGE
1-TK-2 SECOND SLURRY TANK
1-TK-3 SLURRY CONTROL TANK
1-P-3A,B SLURRY TRANSFER PUMP
WATER
WATER
COAL SLURRY TO SYSTEM 3 DWG 524-TX-02
NASA CONTRACT NAS8-33824
5.2.4.
JVF
JVF
524-TX-01
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
COAL PREPARATION AND FEED SYSTEM
7-31-80
MITTELHAUSER Corporation


2-V-1 COAL SLURRY RUN TANK
2-P-1 COAL SLURRY CHARGE PUMP
2-P-2 FEED BOOSTER PUMP
2-R-1 TEXACO GASIFIER
2-V-2 SLAG HOPPER
OXYGEN FROM SYSTEM 6 DWG 524-TX-06
COAL SLURRY FROM SYSTEM 1 DWG 524-TX-01
2-V-1
2-P-1
2-P-2
2-R-1
2-V-2
QUENCH WATER FROM SYSTEM 3 DWG 524-TX-03
RAW GAS TO SYSTEM 3 DWG 524-TX-03
SLAG TO SYSTEM 8
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
TEXACO GASIFICATION SYSTEM 2
5.2.4.
JVF
DMD/JVF
524-TX-02
SEPT 1980

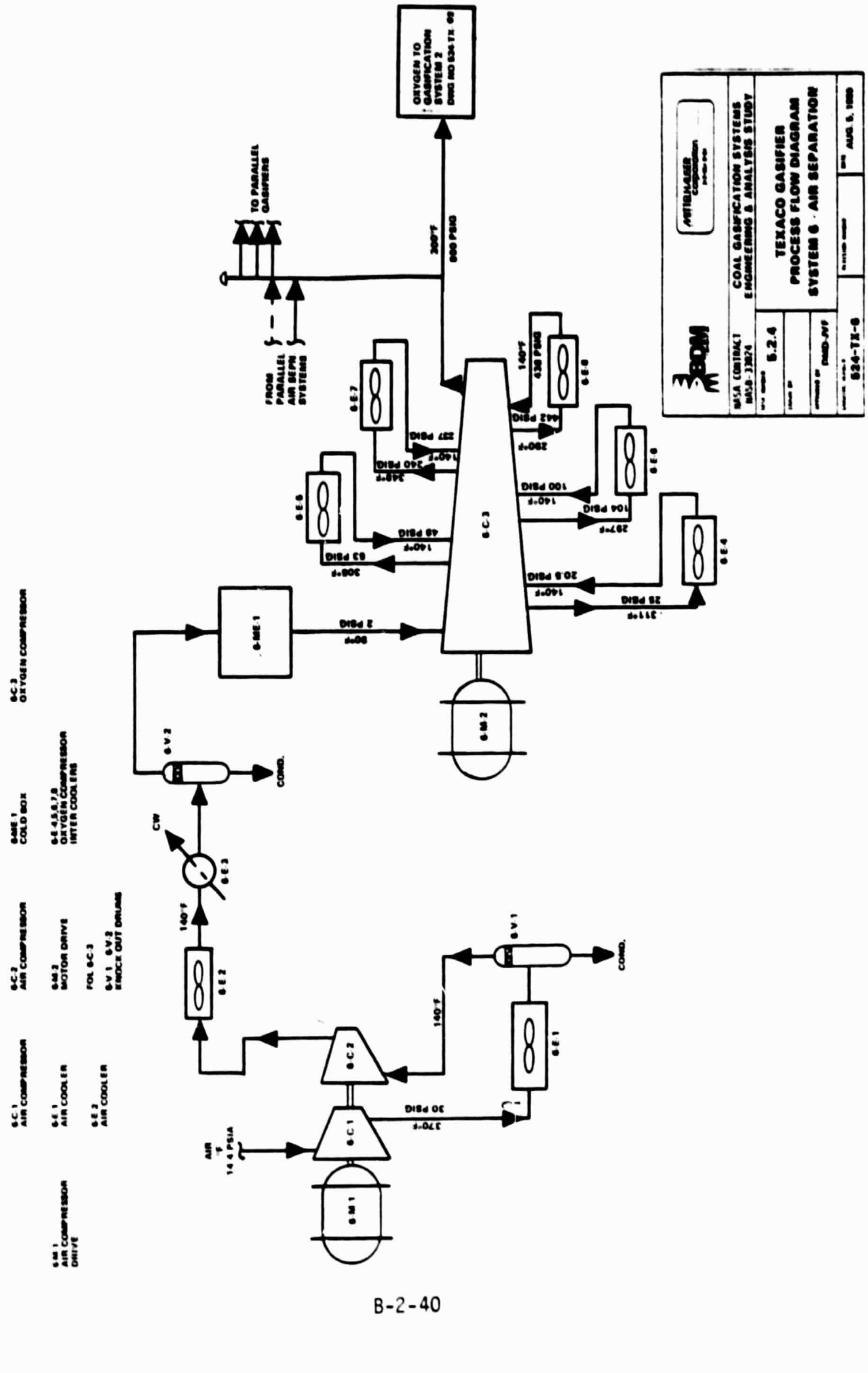

NASA CONTRACT NAS8-33824
6.2.4
DMD-JVF
524-TX-03
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
TEXACO GASIFIER
SYSTEM 3 - INITIAL
GAS CLEANUP & COOLING
FLOW DIAGRAM:
AUG. 5, 1980



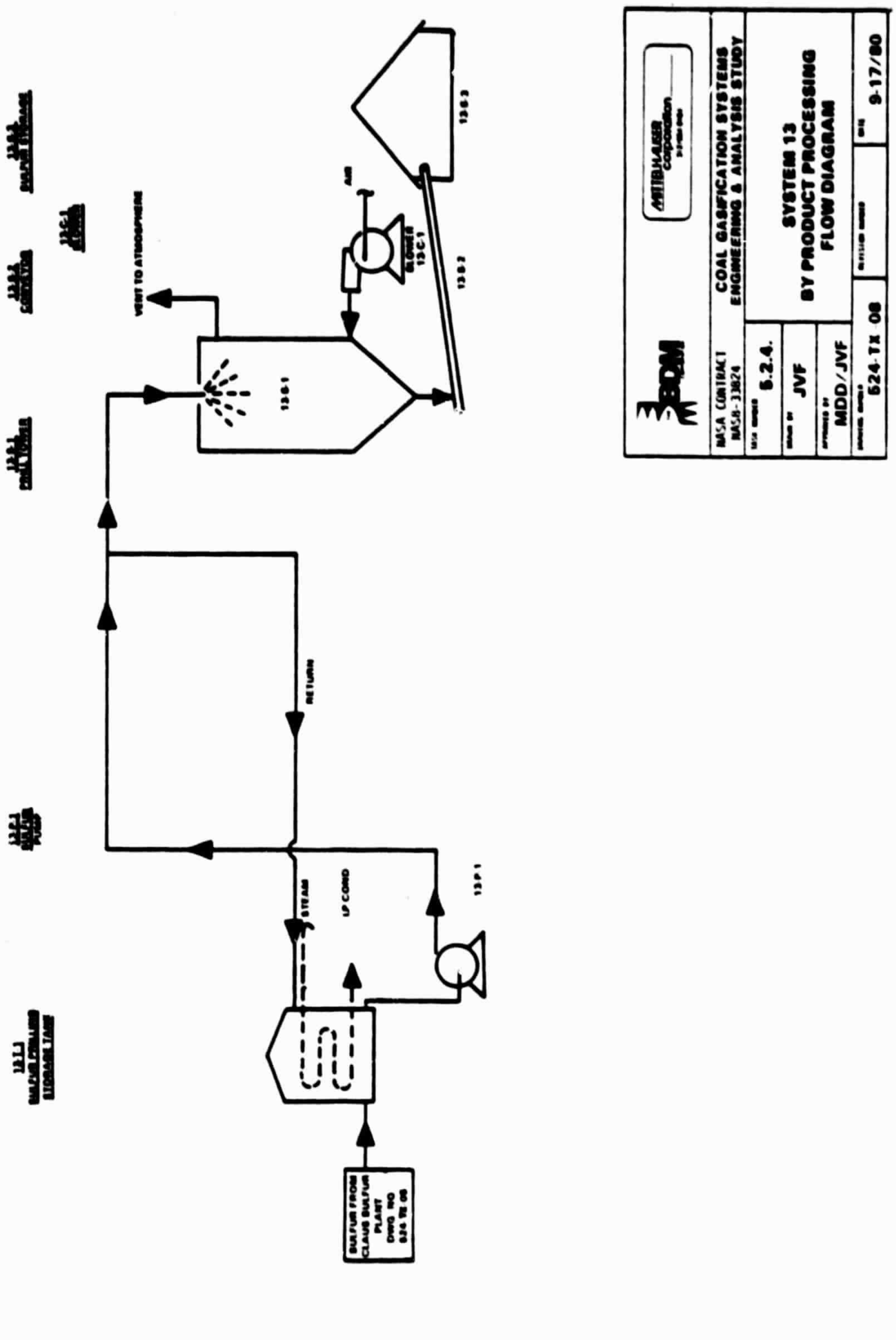
COAL GASIFICATION SYSTEMS
ENGINEERING & ANALYSIS STUDY
SYSTEM 4 - SELEXOL
ACID GAS REMOVAL
FLOW DIAGRAM
5.2.4.
JVF
DMD/JVF
524-TX-04
7-31-80

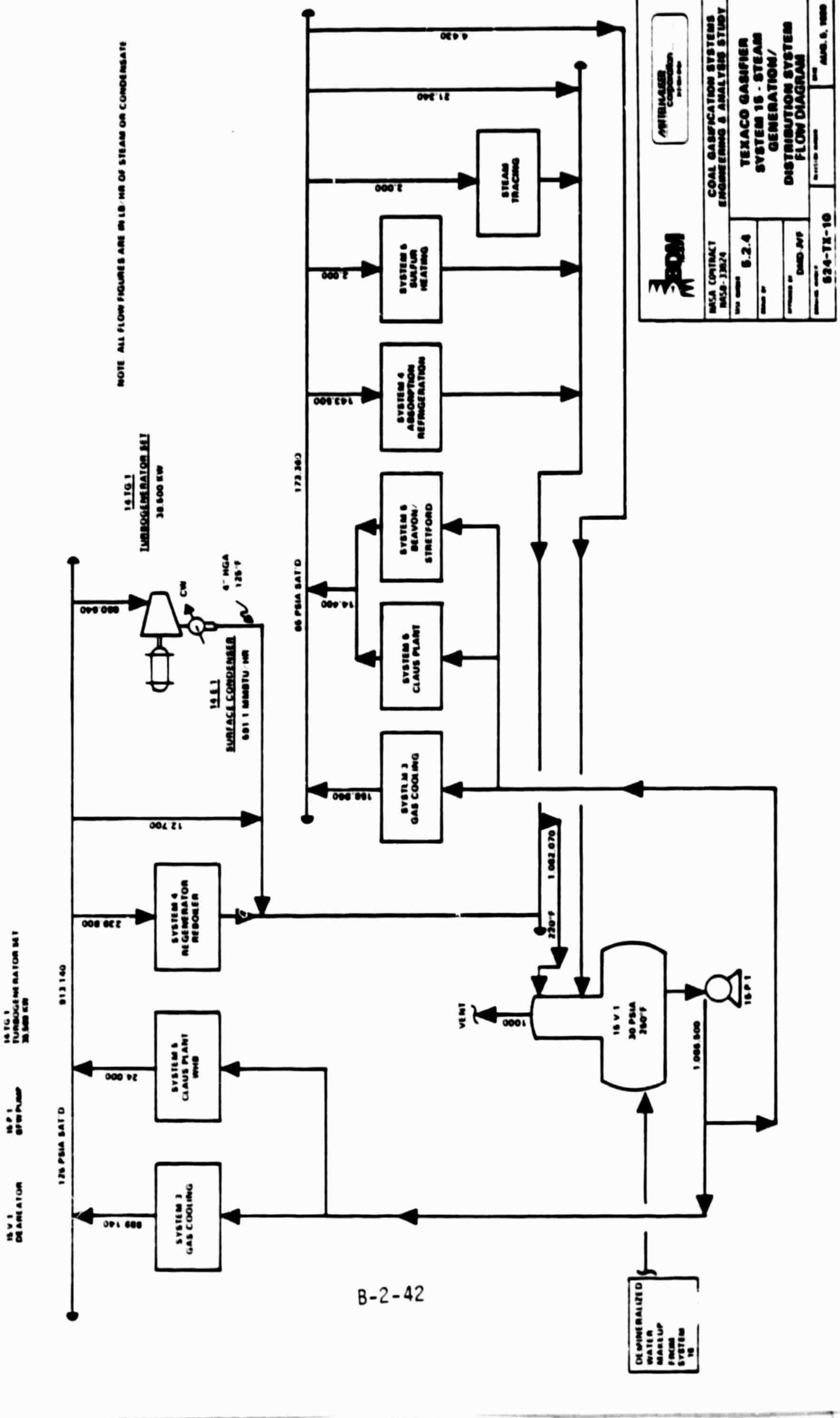


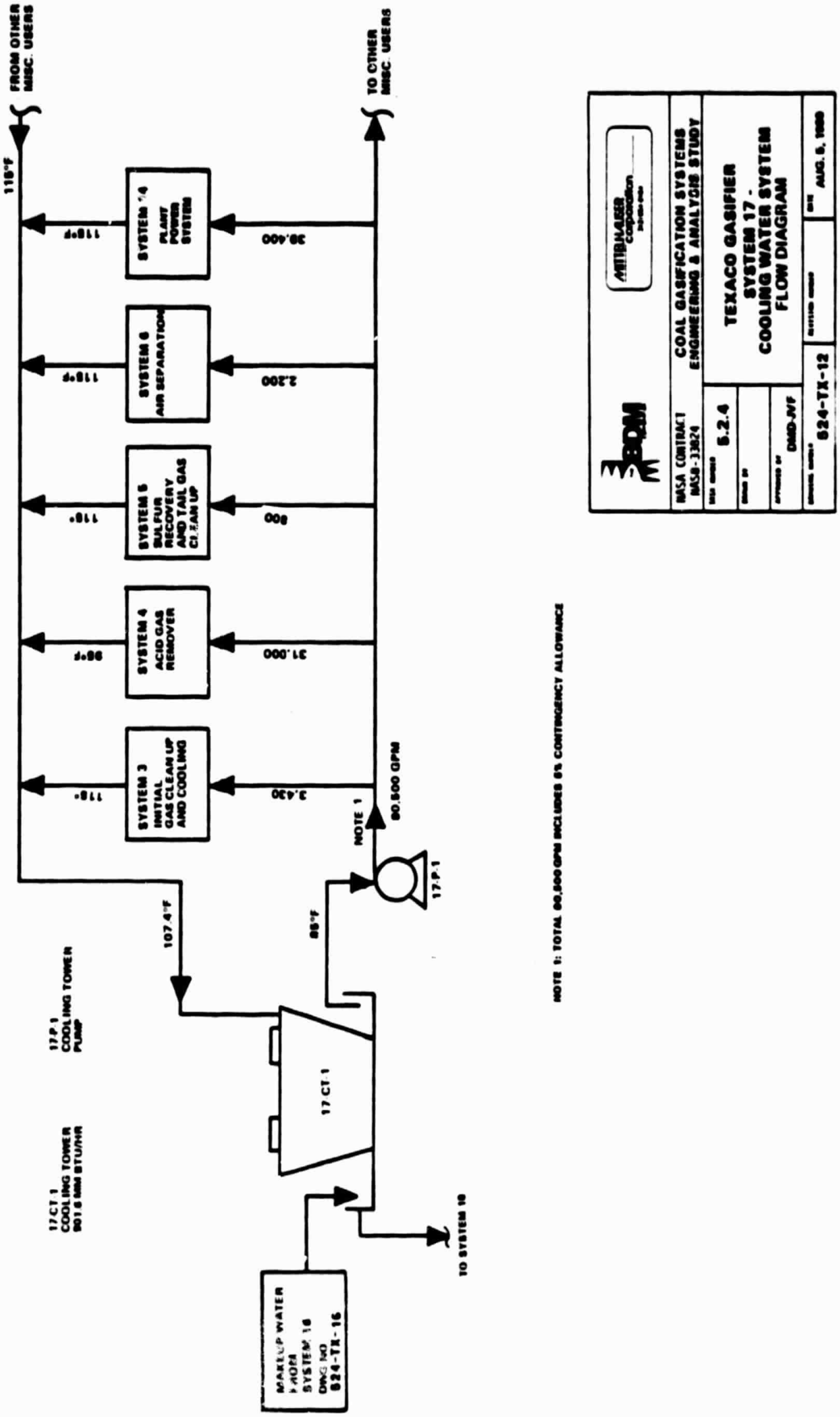
BDM	MITTELHAUSER Corporation
NASA CONTRACT NAS8-33824	COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
5.2.4.	SYSTEM 6 SULFUR RECOVERY
JVF	
MDD/JVF	
524-TX-06	7-31-80

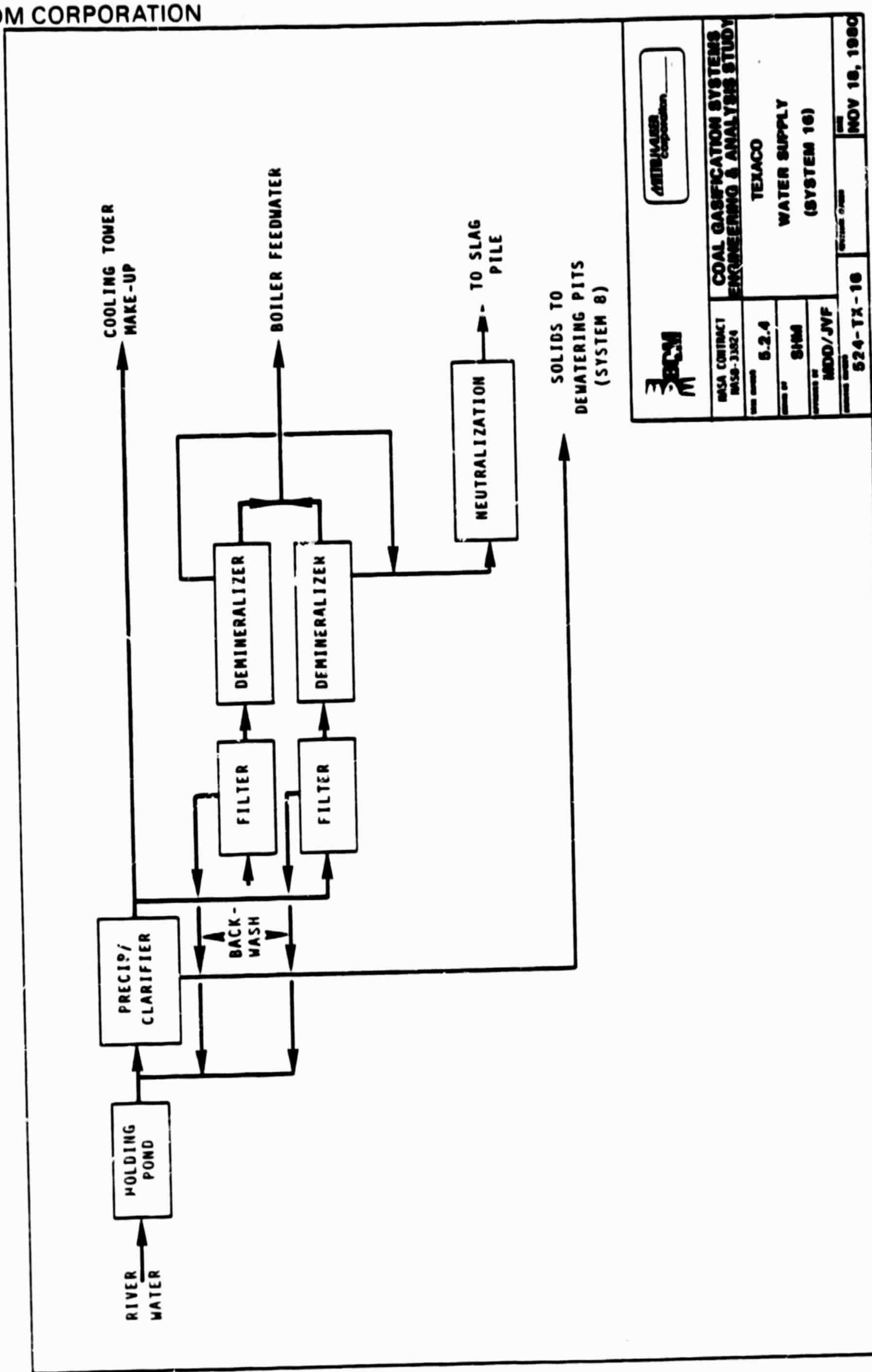


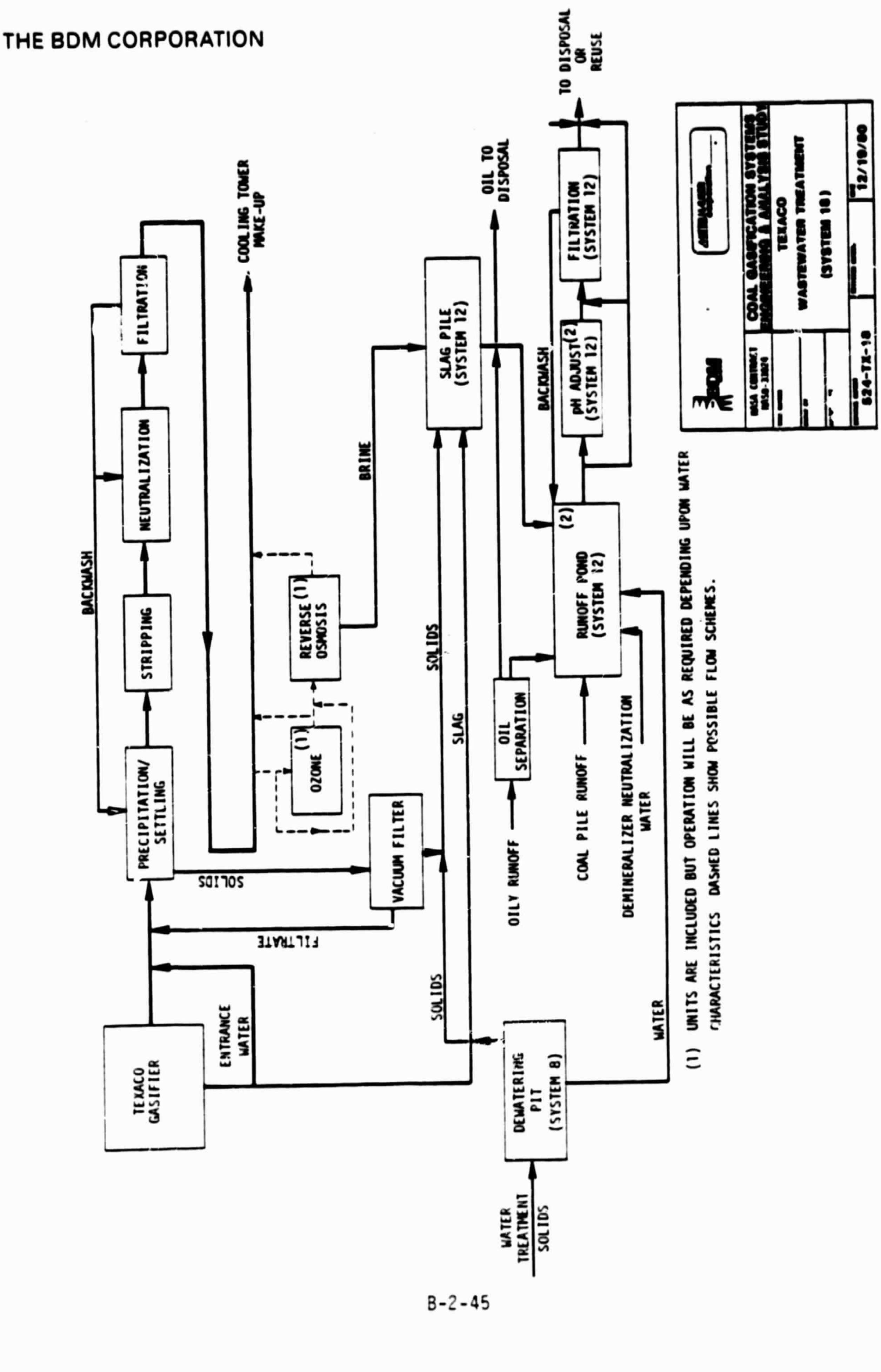
OXYGEN TO GASIFICATION SYSTEM 2
TO PARALLEL GASIFIERS
FROM PARALLEL AIR SEPN SYSTEMS
300°F
800 PSIG
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
TEXACO GASIFIER
PROCESS FLOW DIAGRAM
SYSTEM 6 - AIR SEPARATION
NASA CONTRACT
5.2.4
524-TX-6
AUG. 5, 1980
6-M-1 AIR COMPRESSOR DRIVE
6-C-1 AIR COMPRESSOR
6-E-1 AIR COOLER
6-E-2 AIR COOLER
6-C-2 AIR COMPRESSOR
6-M-2 MOTOR DRIVE FOR 6-C-3
6-V-1 6-V-2 KNOCK OUT DRUMS
6-ME-1 COLD BOX
6-C-3 OXYGEN COMPRESSOR
CW
COND.
AIR
14.4 PSIA
370°F
30 PSIG
140°F


BULFUR FROM CLAUS SULFUR PLANT DWG NO 524 TX 08
STEAM
LP COND
RETURN
13 P 1
13-S-1
13-S-2
13-S-3
VENT TO ATMOSPHERE
AIR
BLOWER 13-C-1
BDM
MITTELHAUSER Corporation
NASA CONTRACT NAS8-33824
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
5.2.4.
JVF
MDD/JVF
SYSTEM 13 BY PRODUCT PROCESSING FLOW DIAGRAM
524-TX 08
9-17/80


NOTE ALL FLOW FIGURES ARE IN LB/HR OF STEAM OR CONDENSATE
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
TEXACO GASIFIER SYSTEM 15 - STEAM GENERATION/ DISTRIBUTION SYSTEM FLOW DIAGRAM
NASA CONTRACT NAS8-33824
5.2.4
624-TX-10
STEAM TRACING
SYSTEM 6 SULFUR HEATING
SYSTEM 4 ABSORPTION REFRIGERATION
SYSTEM 6 BEAVON/ STRETFORD
SYSTEM 6 CLAUS PLANT
SYSTEM 3 GAS COOLING
SYSTEM 4 REGENERATOR REBOILER
SYSTEM 6 CLAUS PLANT WHB
14 TG 1 TURBOGENERATOR SET 38,500 KW
14 E 1 SURFACE CONDENSER
65 PSIA SAT'D
125 PSIA SAT'D
15 V 1 30 PSIA 250°F
15 V 1 DEAERATOR
15 P 1 BFW PUMP
15 P 1
VENT
CW
4" HGA 125°F
220°F
DEMINERALIZED WATER MAKEUP FROM SYSTEM 16
6,430
21,360
2,000
2,000
143,800
172,363
14,600
188,800
12,700
230,800
913,140
24,000
889,140
1,082,070
1,086,500
1000


FROM OTHER MISC. USERS
TO OTHER MISC. USERS
118°F
SYSTEM 14 PLANT POWER SYSTEM
118°F
38,400
SYSTEM 6 AIR SEPARATION
118°F
2,200
SYSTEM 5 SULFUR RECOVERY AND TAIL GAS CLEAN UP
118°
800
SYSTEM 4 ACID GAS REMOVER
98°F
31,000
SYSTEM 3 INITIAL GAS CLEAN UP AND COOLING
118°
3,430
NOTE 1
90,500 GPM
17-P-1
107.4°F
88°F
17 CT 1
17-P-1 COOLING TOWER PUMP
17 CT 1 COOLING TOWER 901.8 MM BTU/HR
TO SYSTEM 10
MAKEUP WATER FROM SYSTEM 16 DWG NO 824-TX-16
NOTE 1: TOTAL 90,500 GPM INCLUDES 5% CONTINGENCY ALLOWANCE
BDM
NASA CONTRACT NAS8-33824
5.2.4
DMD-JVF
824-TX-12
Mittelhauser Corporation
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
TEXACO GASIFIER SYSTEM 17 - COOLING WATER SYSTEM FLOW DIAGRAM
AUG. 5, 1980


RIVER WATER
HOLDING POND
PRECIP/ CLARIFIER
BACK-WASH
FILTER
FILTER
DEMINERALIZER
DEMINERALIZER
NEUTRALIZATION
COOLING TOWER MAKE-UP
BOILER FEEDWATER
TO SLAG PILE
SOLIDS TO DEWATERING PITS (SYSTEM 8)
NASA CONTRACT NAS8-33824
5.2.4
SHM
MDD/JVF
524-TX-16
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
TEXACO
WATER SUPPLY
(SYSTEM 16)
NOV 18, 1980



(1) UNITS ARE INCLUDED BUT OPERATION WILL BE AS REQUIRED DEPENDING UPON WATER CHARACTERISTICS DASHED LINES SHOW POSSIBLE FLOW SCHEMES.

EQUIPMENT LIST
TVA MBG MODULE
TEXACO GASIFIER
SYSTEM NO: 1 - COAL PREPARATION & FEEDING

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
11-S-1	COAL STORAGE			COAL SILO
1-S-1	TRAMP IRON REMOVAL			MAGNETIC
1-CV-1	COAL TRANSPORT TO SYSTEM 1			COVERED CONVEYOR
1-BN-1	FEED SURGE	1	1	700 TON COAL BIN
1-CV-2	CONTROL FEED RATE	1	1	WEIGH BELT CONVEYOR
1-ME-1	CRUSH COAL TO 1/4" x0	1	1	CAGE MILL
1-S-2	SEPARATE COAL AT 1/4"	1	1	VIBRATING SCREEN
1-CV-3	TRANSPORT COAL TO SLURRY PREPARATION	1	1	SCREW CONVEYOR
1-S-3	SAMPLE COAL	1	1	

EQUIPMENT LIST
TVA MBG MODULE
TEXACO GASIFIER
SYSTEM NO: 1 - COAL PREPARATION & FEEDING

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
1-ME-2	FINE GRIND COAL	1	1	ROD MILL (WET)
1-P-1	PUMP SLURRY TO SCREENING OPERATION			CENTRIFUGAL SLURRY PUMP
1-P-2	CIRCULATE WATER FOR SCREENING OPERATION			
1-TK-1	ROD MILL EFFLUENT TANK	1	1	CONICAL BOTTOM SLURRY TANK
1-S-3	FINAL PRODUCT SIZE CONTROL	1	1	WET SCREEN
1-TK-4 A&B	HOLDING TANKS		1	STIRRED FEED SLURRY TANKS
1-ME-3	SLURRY WATER REDUCTION	1	1	CENTRIFUGE
1-TK-3	SLURRY COMPOSITION CONTROL	1	1	SLURRY TANK WITH DENSITY MONITORING FOR MAKEUP WATER CONTROL
1-TK-2	COLLECT CENTRIFUGE EFFLUENT	1	1	DATA SURGE TANK FOR SCREENING OPERATION

THE BDM CORPORATION

EQUIPMENT LIST
TVA MBG MODULE
TEXACO GASIFIER
SYSTEM NO: 1 - COAL PREPARATION & FEEDING

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
1-P-3 A&B	TRANSPORT SLURRY TO SYSTEM 2		1	CENTRIFUGE SLURRY TRANSFER PUMPS

EQUIPMENT LIST
TVA MBG MODULE
TEXACO GASIFIER
SYSTEM NO: 2 - COAL GASIFICATION

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
2-V-1	COAL SLURRY RUN TANK	1	3	ENCLOSED STIRRED TANK WITH PUMP AROUND SYSTEM
2-P-1	PUMP AROUND AND POSITIVE SUCTION SLURRY PUMP			
2-P-2	GASIFIER FEED PUMP	1	3	POSITIVE DISPLACEMENT HIGH PRESSURE SLURRY PUMP
2-R-1	COAL GASIFICATION	1	3	TEXACO REALTOR SYSTEM
2-V-2	SLAG REMOVAL	1	3	TEXACO SLAG REMOVAL SYSTEM

EQUIPMENT LIST
TVA MBG MODULE
TEXACO GASIFIER
SYSTEM NO: 3 - INITIAL GAS CLEANUP & COOLING

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
3-E-1	110 PSIG STEAM GENERATOR	0	5	818.9 MM Btu/hr TOTAL KETTLE TYPE, 15,000 SQ FT/UNIT SHELL: CS; TUBES: SS
3-E-2	50 PSIG STEAM GENERATOR	0	2	144.5 MM Btu/hr TOTAL KETTLE TYPE, 10,080 SQ FT/UNIT SHELL: CS; TUBES: SS
3-E-3	BOILER FEEDWATER HEATER	0	1	53.5 MM Btu/hr TYPE AEL 17,650 SQ FT SHELL: CS; TUBES: SS
3-E-4	RAW GAS AIR COOLER	0	1	100.0 MMBtu/hr AIR COOLER FOUR BAYS, EA. 28'x30', 6 TUBE ROWS, SS TUBES
3-E-5	TRIM COOLER	0	1	10.0 MM Btu/hr TYPE AEL 5650 SQ FT SHELL: CS; TUBES: SS
3-V-1	KNOCKOUT DRUM	0	1	VERTICAL VESSEL 120" ID x 12'-0" T/T C.S. DT: 450°F; DP: 700 PSIG
3-V-2	KNOCKOUT DRUM	0	1	VERTICAL VESSEL 108" ID x 11'-0" T/T C.S. DT: 380°F; DP: 700 PSIG
3-V-3	KNOCKOUT DRUM	0	1	VERTICAL VESSEL 102" ID x 10'-6" T/T C.S. DT: 350°F; DP: 700 PSIG

EQUIPMENT LIST
TVA MEG MODULE
TEXACO GASIFIER
SYSTEM NO: 3 - INITIAL GAS CLEANUP & COOLING

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
3-V-4	KNOCKOUT DRUM	0	1	VERTICAL VESSEL 90" ID x 9'-6" T/T C.S. DT: 200°F; DP: 700 PSIG
3-V-5	AMMONIA SCRUBBER	0	1	VERTICAL VESSEL 114" ID x 20'-0" T/T C.S. w/6 SS SIEVE TRAYS DT: 150°F; DP: 700 PSIG
3-P-1	HOT PROCESS CONDENSATE PUMP	1	2	CENTRIFUGAL PUMP CS/CI DESIGN GPM = 1565 P = 60 PSI
3-P-2	COOL PROCESS CONDENSATE PUMP	1	2	CENTRIFUGAL PUMP CS/CI DESIGN GPM = 72 P = 50 PSI
3-P-3	AMMONIA SCRUBBER BOTTOMS PUMP	1	2	CENTRIFUGAL PUMP CS/CI DESIGN GPM = 93 P = 50 PSI
3-ME-1	GAS SCRUBBING UNIT			TEXACO PROPRIETARY

EQUIPMENT LIST
TVA MBG MODULE
TEXACO GASIFIER
SYSTEM NO. 4 - ACID GAS REMOVAL

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
4-V-1	SOLVENT KNOCK-OUT DRUM	0	1	
4-V-2	SOLVENT FLASH DRUM	0	1	
4-V-3	REGENERATOR KNOCK-OUT	0	1	
4-T-1	ACID GAS ABSORBER	0	1	
4-T-2	SOLVENT REGENERATOR	0	1	
4-E-1	SOLVENT CHILLER	0	1	SHELL & TUBE EXCHANGER
4-E-2	SOLVENT COOLER	0	1	SHELL & TUBE EXCHANGER
4-E-3	REGENERATOR FEED PREHEAT EXCHANGER	0	1	SHELL & TUBE EXCHANGER
4-E-4	ACID GAS COOLER	0	1	AIR FAN EXCHANGER
4-E-5	REGENERATOR REBOILER	0	1	SHELL & TUBE EXCHANGER

THE BDM CORPORATION

EQUIPMENT LIST
TVA MBG MODULE
TEXACO GASIFIER
SYSTEM NO. 4 ACID GAS REMOVER

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
4-P-1	SOLVENT CIRCULATION PUMP	1	1	
4-P-2	REGENERATOR REFLEX PUMP	1	1	
4-P-3	SOLVENT TRANSFER PUMP	1	1	
4-TK-1	SOLVENT STORAGE TANK	0	1	
4-ME-1	TEG GAS DRYING PACKAGE	0	1	INCLUDES TEG CIRCULATION PUMP, TEG CONTRACTOR AND TEG REGENERATOR
4-C-1	RECYCLE VAPOR COMPRESSOR	0	1	
4-HT-1	RICH SOLVENT LET DOWN TURBINE	0	1	

EQUIPMENT LIST
TVA MBG MODULE
TEXACO GASIFIER
SYTEM NO. 5 SULFUR RECOVER & TAIL GAS CLEAN-UP

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
5-P-1	SULFUR PRODUCT PUMP	1	1	
5-P-2	STRETFORD SOUR WATER PUMP	1	1	
5-P-3	REDOX SOLUTION CIRCULATION PUMP	1	1	
5-P-4	STRETFORD SULFUR TRANSFER PUMP	1	1	
5-P-5	REACTION FURNACE AIR BLOWER	1	1	
5-S-1	AIR OXIDATION MIX TANK	0	1	
5-S-2	STRETFORD SULFUR SEPARATOR MELTOR	0	1	
5-S-3	MOLTER SULFUR STORAGE PIT	0	1	

EQUIPMENT LIST
TVA MBG MODULE
TEXACO GASIFIER
SYSTEM NO. 5 SULFUR RECOVERY & TAIL GAS CLEAN-UP

NOTE: THIS ENTIRE UNIT IS DUPLICATED IN MODULE 1 ONLY

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
5-V-1	ACID GAS KNOCK - OUT DRUM	0	1	
5-R-1	REACTION FURNACE	0	1	ACID GAS BURNER AND STEAM GENERATION
5-R-2,3,4	SULFUR CONVERTERS	0	3	HORIZONTAL REACTORS
5-R-S	BEAVON REACTORS	0	1	HORIZONTAL GAS HYDROLYSIS REACTOR
5-T-1	BEAVON UNIT CONDENSER	0	1	
5-T-2	STRETFORD ABSORBER	0	1	
5-E-1,2,3,4	SULFUR CONDENSORS	0	4	SHELL & TUBE EXCHANGER
5-E-5	BEAVON UNIT GAS COOLER	0	1	SHELL & TUBE EXCHANGER
5-E-6	STRETFORD RECYCLE COOLER	0	1	

EQUIPMENT LIST
TVA MBG MODULE
TEXACO GASIFIER
SYSTEM NO: 6 - AIR SEPARATION

ITEM NUMBER	SERVICE	QUANTITY SPARE	QUANTITY OPERATION	DESCRIPTION
6-ME-1	AIR SEPARATION PLANT	0	1	PACKAGE SYSTEM 1657 TPD 98% OXYGEN
6-C-1	AIR COMPRESSOR	0	1	AXIAL COMPRESSOR
6-C-2	AIR COMPRESSOR	0	1	CENTRIFUGAL COMPRESSOR
6-C-3	OXYGEN COMPRESSOR	0	1	CENTRIFUGAL COMPRESSOR
6-M-1	AIR COMPRESSOR DRIVER	0	1	ELECTRIC MOTOR 24,100 Hp
6-M-2	OXYGEN COMPRESSOR DRIVER	0	1	ELECTRIC MOTOR 12,400 Hp
6-E-1	AIR INTERCOOLER	0	1	AIR COOLED EXCHANGER
6-E-2	AIR AFTERCOOLER	0	1	AIR COOLED EXCHANGER

EQUIPMENT LIST
TVA MBG MODULE
TEXACO GASIFIER
SYSTEM NO: 6 - AIR SEPARATION

ITEM NUMBER	SERVICE	QUANTITY SPARE	QUANTITY OPERATION	DESCRIPTION
6-E-3	AIR TRIM COOLER	0	1	
6-E-4	1st STAGE OXYGEN COOLER	0	1	AIR COOLED EXGR. 5.28 MM Btu/hr
6-E-5	2nd STAGE OXYGEN COOLER	0	1	AIR COOLED EXGR. 5.09 MM Btu/hr
6-E-6	3rd STAGE OXYGEN COOLER	0	1	AIR COOLED EXGR. 4.85 MM Btu/hr
6-E-7	4th STAGE OXYGEN COOLER	0	1	AIR COOLED EXGR. 6.45 MM Btu/hr
6-E-8	5th STAGE OXYGEN COOLER	0	1	AIR COOLED EXGR. 4.63 MM Btu/hr

EQUIPMENT LIST
TVA MBG MODULE
TEXACO GASIFIER
SYSTEM NO. 13 BY PRODUCT PROCESSING

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
13-T-1	MOLTEN SULFUR STORAGE TANK	0	2	STEAM HEATED 500 TONS EACH
13-P-1	PRILL TOWER FEED PUMP	1	1	MOLTEN SULFUR PUMP
13-S-1	PRILLING TOWER	0	1	
13-S-2	PRILLED SULFUR CONVEYOR	0	1	
13-C-1	AIR BLOWER	1	1	
13-S-3	PRILLED SULFUR STORAGE	0	1	5000 TONS STORAGE BUILDING

APPENDIX B-3

BABCOCK AND WILCOX COAL GASIFICATION PLANT
REFERENCE FACILITY DESIGN

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1.0 INTRODUCTION

The United States, after a number of years of development based on plentiful and inexpensive oil and natural gas, is entering a period of time when it is essential to supplement these energy sources by the increased use of coal. Coal is the nation's most plentiful fossil fuel. Coal gasification is a means of accomplishing this. While utilization of coal through conversion to gaseous products is not new there is no industry within the US which might serve as a base for establishing cost, operational reliability and requirements, and design data for the large scale environmentally acceptable plants needed.

The Tennessee Valley Authority with systems engineering and analysis support from the George C. Marshall Space Flight Center has initiated a project which would establish the commercial base and demonstrate the requirements for gasifying coal in a large integrated facility. The project consists of gasifying 20,000 tons per day of Eastern coal in a four module plant-the construction of which is staggered to accommodate efficient use of construction manpower and product market development.

The purpose of this study is the systematic engineering and cost analysis of five selected gasifier technologies and the other associated systems required to produce medium BTU gas for delivery into a 600 psig distribution system in Northern Alabama. This effort in a series of design studies provides a reference basis for selection of the final plant configuration and choice of process technologies.

The methodology consists of selection of a systematic breakdown of the facility for purpose of study, identification of available technologies for each system, development of a definition level design and cost analysis for each system, conducting a series of trade studies using the definition design as a basis, and finally development of reference facility designs and cost analyses based on the previous work.

This report covers the work done in establishing a Reference Facility Design based on Babcock and Wilcox coal gasification technology. It is one of three such designs, the other two being based on Koppers-Totzek and Texaco coal gasification processes. The design covers a complete grass roots facility site at Murphy Hill, Alabama. The plant inputs are coal, water and electricity. The plant outputs are medium BTU gas (MBG) and solidified sulfur.

The design approach involved breaking each of four identical modules into process and support systems followed by analysis of each system through identification of available technologies and use of the comparative trade studies to select the preferred processes for each system.

2.0 SUMMARY

A four module, 20,000 TPD, based on B&W coal gasification technology has been designed. The plant processes Kentucky No. 9 coal with provisions for up to five percent North Alabama coal. Coal transportation is by river barge except for the Alabama coal which is trucked to the site. Medium BTU gas with heat content of 303 BTU/SCF and not more than 200 ppm sulfur is the primary plant product. Sulfur is recovered for sale as prilled sulfur. Ash disposal is on site. The plant is designed for zero water discharge. Trade studies provided the basis for not using boiler produced steam to drive prime movers. Thus process derived steam in excess of process requirements is superheated for power use in prime movers. Electricity from the TVA grid is used to supply the balance of the plant prime mover power requirements. A study of the effect of minemouth coal cleaning showed that coal cleaning is not an economically preferred route.

The plant design was arrived at by a systematic procedure based on published design work, process trade studies, team engineering experience, a NASA provided module level definition of some twenty systems, and the TVA document, "Design Criteria for Conceptual Designs and Assessments of TVA's Coal Gasification Demonstration Plant," March, 1980.

The overall plant configuration is shown schematically in Figure 2.1. As shown, General Facilities, Instrumentation and Control, and Coal Handling serve plant wide functions. All other plant components are contained in four identical process modules. The Instrumentation and Control System operates to monitor overall plant performance and to control intermodule relationships. The total list of systems is given in Table 2.1.

The design procedure involved defining available processes to meet the requirements of each system, technical/economic trade studies to select the preferred processes, and engineering design and flow sheet development for each module. Cost studies assumed a staggered construction schedule for the four modules beginning spring 1981 and a 90 percent on stream factor.

The basis and results of the design study are given in Tables 2.2 and 2.3.

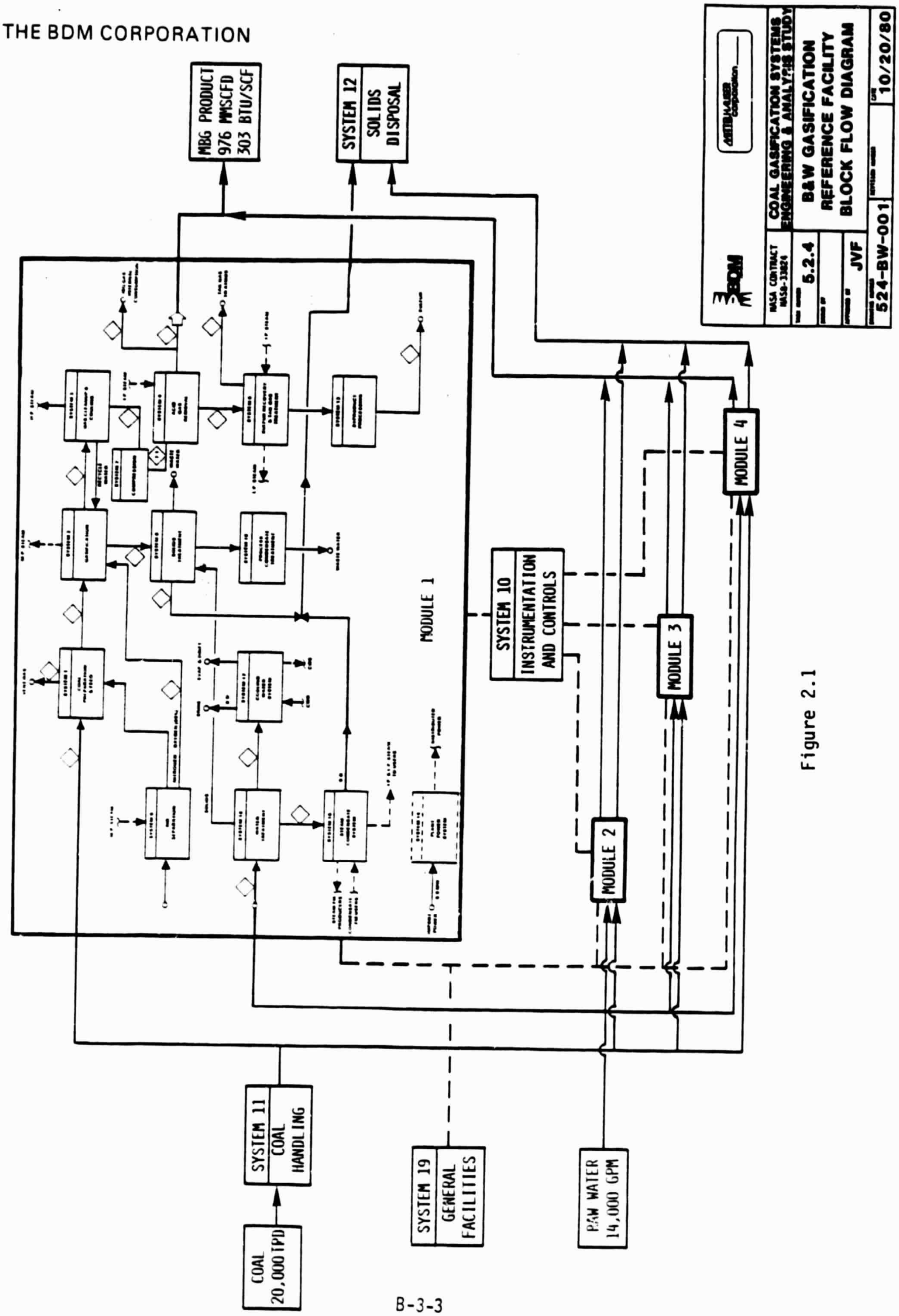

MBG PRODUCT
976 MMSCFD
303 BTU/SCF
SYSTEM 12
SOLIDS DISPOSAL
MODULE 1
SYSTEM 10
INSTRUMENTATION AND CONTROLS
MODULE 2
MODULE 3
MODULE 4
SYSTEM 11
COAL HANDLING
COAL
20,000 TPD
SYSTEM 19
GENERAL FACILITIES
RAW WATER
14,000 GPM
NASA CONTRACT
NAS8-33824
5.2.4
JVF
524-BW-001
COAL GASIFICATION SYSTEMS
ENGINEERING & ANALYSIS STUDY
B&W GASIFICATION
REFERENCE FACILITY
BLOCK FLOW DIAGRAM
10/20/80

Figure 2.1

TABLE 2.1. LIST OF SYSTEMS

SYSTEM NO.	NUMBER OF PER MODULE	COST UNITS PER FACILITY	SYSTEM DESCRIPTION
1	1	4	COAL PREPARATION AND FEEDING
2	3	12	GASIFICATION
3	3	12	INITIAL GAS CLEANUP AND COOLING
4	1	4	ACID GAS REMOVAL
5	1	5	SULFUR RECOVERY
6	2	8	AIR SEPARATION
7	1	4	COMPRESSION
8	1	4	PROCESS SOLIDS TREATMENT
10	0	1	INSTRUMENTATION AND CONTROL
11	0	1	COAL HANDLING
12	0	1	SOLIDS DISPOSAL
13	1	4	BY-PRODUCT PROCESSING
14	1	4	PLANT POWER SYSTEM
15	1	4	STEAM GENERATION/DISTRIBUTION
16	1	4	RAW WATER MAKE-UP
17	1	4	COOLING WATER SYSTEM
18	1	4	WASTE WATER TREATMENT
19	1	1	GENERAL FACILITIES

TABLE 2.2. DESIGN BASIS SUMMARY*

PLANT CAPACITY	20,000 TPD
PLANT TYPE	FOUR INDEPENDENT MODULES
COAL TYPE	KENTUCKY NO. 9
PLANT SERVICE FACTOR	90 PER CENT
PLANT LIFE	20 YEARS EACH MODULE
ELECTRICITY SOURCE	TVA GRID-4.16KV, 6.9KV, 13.8KV
WATER	TENNESSEE RIVER
COAL RECEIPT	BARGE +5% BY TRUCK
PRODUCT DELIVERY	MBG AT 600 PSIG
PRODUCT QUALITY	MINIMUM 285 Btu/SCF
SULFUR	PRILLED
COAL COST (1980)	$1.25/MM Btu
LAND COST (1980)	$3,000/ACRE
CLEARING AND GRUBBING (1980)	$2,000/ACRE
ELECTRICITY COSTS (1980)	
BY-PRODUCT CREDIT	NONE
ESCALATION	AS PER TVA SPECIFICATION

*Design Criteria for Conceptual Designs and Assessments of TVA's Coal Gasification Demonstration Plant," Tennessee Valley Authority, March, 1980

TABLE 2.3. DESIGN STUDY RESULTS*

FEED COAL	6,570,000 TPY
WATER	14,000 GPM
PURCHASED ELECTRICITY	183 MM KWHY
MBG PRODUCT	976 M MSCFD
MBG PRODUCT	322 MM MSCFY
MBG QUALITY	303 BTU/SCF
SULFUR PRODUCT (PRILLED)	673 LTPD
SULFUR PRODUCT	222,000 LTPY
TOTAL CAPITAL REQUIREMENTS**	$3,347 MM ($2,567 MM)
OPERATING AND MAINTENANCE COSTS	$138 MM/YR
COAL, CATALYST, CHEMICALS	$181 MM/YR
PLANT OPERATING STAFF	271 PERSONS
MAINTENANCE/YEAR	97 MM

* COSTS ARE IN 1980 DOLLARS
**BASED ON INSTALLATION FACTOR OF 2.31 AND 1.5. (SEE CHAPTER V.A.)

Designs in this study were based on published works, engineering experience and judgments, and consultations with appropriate process and equipment vendors followed by design calculations, flow process sheet development and documentation.

Cost estimates are based on normal conceptual level design estimating procedures as described in the "Coal Estimation and Economic Evaluation Methodology," BDM/W-80-258-TR-RV2, submitted as another part of this project work scope and reprinted as Appendix E. Schedule estimates are in accordance with overall guidelines furnished by NASA.

Details of the schedule are considered typical for projects of this type and while they do not represent a detailed analysis specific to this project they represent the complexity and illustrate schedule constraints associated with the subject project. Process flow diagrams are included for the main process systems, air separation system, cooling water system, and steam distribution system as aids in following written system descriptions.

Technical results of the study are reported in this appendix. A cost analysis is included as a part of Appendix D.

3.0 OVERALL FACILITY DESCRIPTION

This section presents and discusses the process design of a plant designed to gasify 20,000 tons per day of coal in four 5000 TPD modules and to produce a medium-Btu product fuel gas (MBG) with a higher heating value of 303 Btu/SCF. The plant design is based upon using entrained flow gasifiers as offered by the Babcock & Wilcox Company, and upon the design criteria (coal characteristics, product specifications, site data, etc.) set forth by the Tennessee Valley Authority in March, 1980.

3.1 Overall Plant Processing

The overall plant configuration is shown in the block flow diagram, see Figure 2.1. Kentucky No. 9 coal is received by barge and either placed in a dead storage pile or processed in System 11, Coal Handling. Provisions have also been made to receive up to five per cent of plant capacity by truck. Dead storage provides for 90 days of supply in interruption.

Coal, either directly from barges or from dead storage, is processed in a Bradford breaker and conveyed to four process modules of 5000 TPD capacity each.

In each module, the raw coal fed to the plant from System 11 is crushed and dried in System 1 and fed to System 2, the Babcock & Wilcox gasifiers, along with unconverted char which is recovered and recycled from the gasifier outlet gas cyclones. The feed coal and recycle char are partially combusted (within the gasifier), with oxygen supplied from the air separation plant, to form a raw product gas which is rich in carbon monoxide and hydrogen. The raw gas leaves the gasifiers at 1800°F and 240 psia, passes through primary cyclones for partial recovery of char recycle, and is then cooled to 450°F in waste heat recovery boilers. Heat recovered in the waste heat boilers and from the gasifiers is used to generate steam for the plant. The raw gas from the waste heat boilers passes through secondary cyclones for additional recovery of char recycle. The gas is then further cooled to 100°F in Venturi scrubbers, which also function to dehumidify the gas and to remove residual char and ash particulates, in System 3. Initial Gas Cleanup and Cooling System.

The raw gas leaves the Venturi scrubbers at 100°F and about 200 psia. It is then compressed in System 7 to about 640-650 psia and sent to System 4, the Acid Gas Removal, where essentially all of the hydrogen sulfide and carbonyl sulfide, and about 45 per cent of the carbon dioxide contained in the raw gas is removed. The acid gas removal system uses the Selexol process (licensed by the Allied Chemical Corporation) in which a physical solvent (the dimethyl ether of polyethylene glycol) absorbs and removes hydrogen sulfide, carbonyl sulfide and the concomitant carbon dioxide from the raw gas.

The acid gas (hydrogen sulfide, carbonyl sulfide and carbon dioxide) is recovered from the Selexol solvent and processed in System 5, Sulfur Recovery and Tail Gas Treatment, wherein over 99 per cent of the hydrogen sulfide and carbonyl sulfide is converted into 188 short tons/day of by-product elemental sulfur. The sulfur recovery unit utilizes the conventional Claus process to convert about 90 to 95 per cent of the hydrogen sulfide (and some of the carbonyl sulfide) in the acid gas into by-product sulfur. The residual tail gas from the Claus unit is then processed in a Beavon-Stretford unit to recover additional by-product sulfur.

Oxygen utilized for the partial combustion of coal and recycle char in the gasifiers is produced in System 7, a conventional air separation plant. Atmospheric air is compressed to about 100 psia, cooled to 100°F and then separated cryogenically into oxygen and nitrogen at about 2 psig. The oxygen is compressed to about 290 psia for use in the gasifiers. A small portion of the nitrogen is also compressed, to about 295 psia, for use in transporting pulverized coal into the gasifiers.

In addition to the systems contained in each module and described in Section 4, the plant consists of System 10, the overall plant monitoring and control system; System 11, the coal handling and storage system serving all four modules; and System 12, the solid waste disposal system serving the total facility.

The purpose of System 10 is to provide operational monitoring and supervisory master control of module operations. The system includes instrumentation to measure key characteristics of all major streams (mass, temperature, pressure, composition, density, and/or others as appropriate) and to display these characteristics in a central location. A dedicated computer is provided to record data of interest at the facility management level. Telecommunications capabilities are provided to communicate with module and systems operations as required to control total plant operation to meet delivery requirements.

System 11, the Coal Handling System, provides for the unloading of coal delivered to the plant either by barge or truck, reclaiming the coal from storage, reducing the size of coal, and transporting the coal to Coal Preparation and Feeding, System 1.

Raw coal is unloaded from barges by the barge unloading subsystem which is designed to unload up to ten 1500-ton capacity barges per shift. The coal is unloaded at an average rate of 1200 tons per hour on a five-day week basis. Coal is transferred by conveyor to a radial stacker which then produces a kidney-shaped coal pile containing live and dead storage. Coal is reclaimed from live storage and conveyed to a Bradford breaker where it is reduced in size to 1.25x0. Coal from trucks is unloaded into a chute from which it is conveyed to the Bradford breaker. Crushed coal from the Bradford breaker is transported to day storage silos from which it is transferred via vibrating belt conveyors to coal preparation and feeding, System 1, for further processing. Coal fines from the Bradford breaker are collected and sent to the gasification unit, System 2.

The purpose of System 12 is to store solid waste generated by facility operation during the facility life.

This system consists of a lined impounding pit sized to contain 20 years of solid waste. It includes the conveyor system to move the solids to the pit and a leachate recovery area to recover and pump leachate to the process condensate system.

Module descriptions are the subject of Section 4.

3.2 Facility Balances

The key material inputs and product outputs for the overall plant may be summarized as:

INPUTS:	Raw Coal	20,000 short tons/day
	98% Oxygen	15,400 short tons/day
	Raw Water Intake	14,000 gpm
	Imported Electric Power	68 MW
OUTPUTS:	Product Gas	976 MM SCFD
	By-product Sulfur	673 long tons/day
	Solids to Disposal (Wet)	4,335 tons/day
	Solids to Disposal (Dry)	3,252 tons/day

Table 3.1 gives the thermal efficiency for the facility. Table 3.2 gives the final product characteristics.

TABLE 3.1. CONVERSION EFFICIENCY - BABCOCK & WILCOX PROCESS
20,000 TPD FACILITY

INPUTS	10^6 BTU/HR	PER CENT
① COAL TO FACILITY	18,300	
② ELECTRIC POWER TO FACILITY	80	
OUTPUTS		
③ MBG FROM FACILITY	12,235	
④ COAL FINES FROM FACILITY	-0-	
EFFICIENCY		
COAL-TO MBG (③ ÷ ①) x 100%		66.9
OVERALL PRODUCT EFFICIENCY ③ ÷ (① + ②) x 100%		66.6
OVERALL FACILITY EFFICIENCY ③ + ④ ÷ (① + ②) x 100%		66.6

TABLE 3.2. PRODUCT CHARACTERISTICS

	VOLUME PER CENT
CARBON MONOXIDE	63.3
HYDROGEN	30.7
NITROGEN AND ARGON	3.4
CARBON DIOXIDE	2.6
	100.0
HYDROGEN SULFIDE	4.4 PPM VOLUME
CARBONYL SULFIDE	19.9 PPM VOLUME
TOTAL SULFUR	24.3 PPM VOLUME
WATER VAPOR	7.0 LBS/MM SCF
HIGHER HEATING VALUE	303 BTU/SCF
TEMPERATURE	75 ^{o}F
PRESSURE	615 PSIA

4.0 MODULE DESCRIPTIONS

Each of the four modules in the plant consist of identical sequences of process systems as given in Table 2.1. Process flow diagrams and an equipment list are included in Section 5 for the principal process systems and such auxiliary systems, as cooling water and steam systems.

Each module receives 5000 TPD of coal from System 11, Coal Handling. The sequence of processing shown in Figure 2.1 is repeated in each of the four modules. Descriptions of each modular system are as follows.

4.1 System Descriptions

4.1.1 System 1 - Coal Preparation and Feeding

The coal preparation system receives 5,000 tons/day of crushed, raw coal ranging in size from 1.25" to 0". The raw coal is first pulverized (to 70% passing through a 200 mesh screen) and dried. Drying is accomplished by sweeping hot flue gas, at 450°F, through the coal pulverizer. The hot flue gas is generated in a direct-fired air heater using MBG produced inplant as fuel. The dry, pulverized coal is separated from the flue gas in a cyclone recovering about 80 percent of the coal. The remaining 20 percent of the pulverized coal (fines) in the flue gas is recovered by venting the flue gas through a fabric filter baghouse. The pulverized coal from the cyclone and from the baghouse sent to a reservoir tank of about 8 hours storage, where it is stored at atmospheric pressure.

Since the gasifier operates at a pressure of 240 psia, it is necessary to pressurize the coal to about 290 psia for transport and injection into the gasifier. Two lock hoppers, each of 20 minutes storage, are pressured with compressed nitrogen. The nitrogen is obtained from the air separation plant. The pressurized coal from the lock hoppers is fed into a pressurized coal feed tank of about 40 minutes storage, from which the pulverized coal is transported to the gasifier using a portion of the compressed nitrogen as the transport medium.

Each of the lock hoppers operates in sequence with this cycle:

- The lock hopper receives coal from the reservoir tank at atmospheric pressure.
- The hopper inlet and outlet valves are closed, and the hopper is pressurized with compressed nitrogen.
- The hopper is held under pressure until feeding is required, as signalled by hydraulic load cells on the gasifier coal feed tank.

- The hopper outlet valve is opened and coal flows into the gasifier coal feed tank.
- The hopper outlet valve is closed and the hopper vent valve is opened. The hopper is de-pressured and compressed nitrogen is vented through a baghouse for recovery of coal fines.
- The de-pressured lock hopper is ready to again receive coal from the coal reservoir tank.

Coal from the gasifier coal feed tank is continuously transported, using compressed nitrogen, into the gasifier. Drawing No. 524-BW-01 illustrates this system as well as Systems 2 and 3.

4.1.2 System 2 - Gasification

The gasification system includes coal, oxygen and recycle char injection nozzles, the gasifier vessel, slag removal equipment and a steam drum system.

The gasifier vessel consists of a vertical, cylindrical outer steel shell with an inner shell of water-cooled tubes (water wall) in which steam is generated by heat transferred into the tubes from the gasification zone. In the hot reaction zone (lower part of the gasifier), the tubes are covered with a dense refractory to protect the tubes from the molten, flowing slag and yet permit the high temperature required to maintain the gasification reactions and to maintain the slag as a molten fluid. Above the hot reaction zone, the gasification reactions are essentially completed and molten slag is not present. Thus, the inner shell of water-cooled tubes in the upper part of the gasifier is left bare (no refractory covering) to maximize heat transfer from the hot raw gas product into the tubes. The raw gas leaves the gasifier top at 1,800°F and 200 psia, and the molten slag leaves the gasifier bottom at 3,000°F.

Coal recycle char and oxygen are injected into the gasifier at two levels near the vessel bottom. Each level has a ring header with injection nozzles distributed around the periphery of the vessel.

The molten slag formed in the gasifier is a mixture of ash (from the feed coal) and unconverted coal char. The molten slag drains continuously from the gasifier bottom and is quenched and shattered in a water-filled, pressurized slag quench tank. At intermittent intervals, the quenched slag is drained from the quench tank into a slag lock hopper from which the slag is sluiced to dewatering facilities.

Water from an elevated steam drum is pumped into the bottom of the gasifier's water-cooled tubes, and a mixture of steam and water returns from the top of the tubes to the steam drum. The steam-water mixture is separated in the steam drum. The steam is made available for use within the plant and the water is recirculated to the gasifier tubes. Makeup boiler feedwater enters the steam drum and boiler blowdown water is discharged from the drum.

4.1.3 System 3 - Initial Gas Cleanup and Cooling

Complete gasification of the coal is not realized in one pass through the gasifier. Therefore, facilities are provided to recover char (coal ash and unconverted coal) from the raw product gas and to recycle it into the gasifier. Two cyclone stages are provided for that purpose. The hot gas from the gasifier flows through the primary char recovery cyclone stage at 1800°F and is cooled down to 450°F in the WHB (waste heat recovery boiler). The 450°F gas then flows through the secondary char recovery cyclone stage. The collected char from the primary and secondary cyclones is transported back into the gasifier injection nozzles by using steam as the transport medium. The 1800°F char from the primary cyclone passes through a char cooler and is cooled to 1200°F. The recycle char mixture of primary cyclone char (1200°F), secondary cyclone char (450°F) and steam has a temperature of about 900°F entering the gasifiers.

The WHB is designed to remove sensible heat from the hot raw gas as it is cooled from 1800°F down to 450°F and convert the recovered heat into steam. This is accomplished by using an inner shell of water-cooled tubes (water wall) as well as tubes configured cross-current to the gas flow.

The 450°F raw gas leaving the secondary char cyclone still contains a significant amount of unrecovered char and is well above its water dewpoint (calculated to be about 190°F). The gas passes through a Venturi scrubber and is cooled to 100°F, which is below its water dewpoint and therefore water is condensed out of the gas (i.e., the gas is dehumidified). At the same time, the Venturi scrubber removes essentially all of the residual char particulates from the gas. The clean, cool gas then flows to the gas compressors. Since the gas still contains sulfur compounds (hydrogen sulfide and carbonyl sulfide), it is referred to as 'sour' gas.

The gas cooling facilities in the gas cleaning and cooling train may be summarized as:

Waste Heat Boiler: Cools the gas from 1800°F to 450°F and recovers 340 million Btu/hr of heat which is converted into steam. The waste heat boiler includes a steam drum similar to the one described above for the gasifier.

Venturi Scrubber: Cools the gas from 450°F to 100°F and condenses out 22,500 lbs/hr (45 gpm) of water. The total heat removed is 104 million Btu/hr. 70 million Btu/hr is removed by water-cooling a circulating sidestream in the upper section of the Venturi scrubber, and 34 million Btu/hr is removed by makeup water fed to the scrubber.

The performance of the char removal facilities in the gas cleaning and cooling train may be summarized as:

Primary Char Cyclone:	Removes 85% of the char in the gasifier outlet gas.
Secondary Char Cyclone:	Removes 33% of the residual char (5% of the original char content).
Venturi Scrubber:	Removes essentially 100% of the residual char (10% of the original char content).

Discussion of Process Design Elements

The raw coal feed rate of 5,000 T/D per gasification module was established in the Tennessee Valley Authority's design criteria. As tabulated later herein, some of the sub-systems within the 5,000 T/D module were designed as single trains and some as multiple trains. For example, the gasifier sub-system was designed as three trains (each of 2,500 T/D coal gasification) with two trains in operation and the third train in standby service. HOWEVER, ALL OF THE DESIGN DATA PRESENTED IN THIS DISCUSSION (AND ON THE GASIFICATION SECTION PROCESS DESIGN DIAGRAM) ARE FOR THE FULL 5,000 T/D COAL GASIFICATION MODULE.

During the work on this project, preliminary design information was made available by the Babcock & Wilcox Company. That information is referred to herein as the 'B&W design', which compares in feed rate with the design herein as follows:

	This Design	B&W Design
Raw coal feed, T/D	5,000	5,368
Raw coal moisture, %	9.6	6.9
Dry coal feed, T/D	4,824	5,000
Dry coal moisture, %	2.0	0.0

The coal drying equipment was designed to reduce the water content of the coal from 9.6 percent in the raw coal to 2.0 percent in the dry, pulverized coal, which requires removing 32,200 lbs/hr of water from the coal. Removing that amount of water, and heating the coal to 150°F, requires about 50 million Btu/hr of heat including an allowance for heat loss. The amount of flue gas, entering the pulverizer at 450°F and leaving at 150°F, must be about 695,000 lbs/hr to transfer 50 million Btu/hr of heat. To generate a flue gas at 450°F, the direct-fired air heater must be supplied with about 10.5 times the stoichiometric combustion air needed to burn the MBG fuel gas. Thus, the required air rate to the heater is 142,000 SCFM and the fuel required is 70 million Btu/hr.

Pressurizing the coal lock hoppers and feed tank was taken to require about 17,000 lbs/hr. The amount of nitrogen needed to transport dry coal into the gasifiers was also taken to be 17,000 lbs/hr, and that amount of nitrogen was included in the hot product gas from the gasifier in addition to the nitrogen derived from the coal itself.

All of the flue gas from the pulverizer and all of the pressurizing nitrogen was assumed to be vented from the two baghouses in the coal preparation system.

Compressing 34,000 lbs/hr of nitrogen was calculated to require 2,431 HP of compression.

A material balance around the gasifier was developed by pro-rating from the B&W design. Based on that material balance, the carbon conversion in the gasifier was calculated to be 97.5 percent, which coincides with B&W's design information for the selected oxygen-to-coal ratio. The material balance was checked to see that each component (carbon, oxygen, nitrogen, hydrogen and ash) also balanced. After confirming the material balance, an enthalpy data base was developed and the heat balance around the gasifier was calculated. The heat balance indicated that about 500 million Btu/hr must be removed from the gasifier by generating steam, which coincides quite well with the B&W design.

Having confirmed the enthalpy data base, the slag quench duty of 42 million Btu/hr and the recycle char cooling duty of 25 million Btu/hr were calculated by using that enthalpy data base.

Using the same enthalpy data base, a heat curve was developed for the gasifier outlet gas, plotting incremental heat content versus temperature, from 1800°F down to 100°F. The heat curve indicated that about 340 million Btu/hr could be recovered by cooling the gas from 1800°F down to 450°F, which again coincides quite well with the B&W design and further validates the enthalpy data base which was used.

The heat curve also indicated that cooling of the gas from 450°F to 100°F in the Venturi scrubber would require a total heat removal of 104 million Btu/hr. It is not possible to compare this heat removal duty with that of the B&W design which does not indicate the exit temperatures from their Venturi scrubber. However, a water balance around their scrubber indicates that the B&W scrubber was only cooling the gas down to about 155°F. Since the gasifier heat balance and the waste heat boiler duty had coincided well with the B&W design, and therefore validated the enthalpy data being used, it was decided that the heat curve developed from that data was correct. Thus, the total heat removal across the Venturi scrubber was taken as 104 million Btu/hr. The design of the Venturi scrubber, which is integrated with the cooling and recovery of the slag sluice water, is discussed in Section 5.05.

4.1.4 System 8 - Process Solids Treatment

This section describes and discusses the design of the gasification section cooling system, which supplies the integrated cooling requirements for quenching the gasifier slag and for supplying part of the Venturi scrubber cooling. As shown in the following diagram (at the end of this section), the integrated gasification water loop functions to recover and reuse the slag sluice water as well as to cool the water. The clarifier in the system serves to dewater the process solids byproduct before transporting to disposal.

4.1.4.1 Description of the Gasification Section Water Loop

The slag sluice water is heated by absorbing the slag quenching duty. Since the water is recycled for reuse, it must be cooled to remove the heat absorbed and the slag solids must be removed from the water. For those purposes, the slag sluice water is circulated through a clarifier (to remove the solids) and a cooling tower (to remove the heat).

The water content of the wet slag sludge removed in the clarifier functions, for all intents and purposes, as the blowdown from the cooling tower. However, the cooling tower requires makeup water to compensate for the blowdown plus the evaporation and drift losses to the atmosphere. The sum of the blowdown water plus the evaporation and drift losses (see gasification water loop diagram) determines the makeup rate to be 268,200 lbs/hr. The makeup water is introduced into the system by first passing through the Venturi scrubber where it functions to remove part of the total heat removed in the scrubber. Since the Venturi scrubber condenses about 22,500 lbs/hr of water from the raw gas, the amount of makeup water needed is reduced to 245,700 lbs/hr. The heat removed by the makeup water (and, in some part, by the condensed water) in passing through the Venturi scrubber amounts to about 34 million Btu/hr. Since the total heat removal duty across the Venturi scrubber is 104 million Btu/hr, the remaining duty of 70 million Btu/hr is supplied by the plant's utility cooling tower via a circulating sidestream cooler on the scrubber.

The flow stream temperatures and compositions, and an overall heat and material balance for the gasification water loop are given in the diagram at the end of this section.

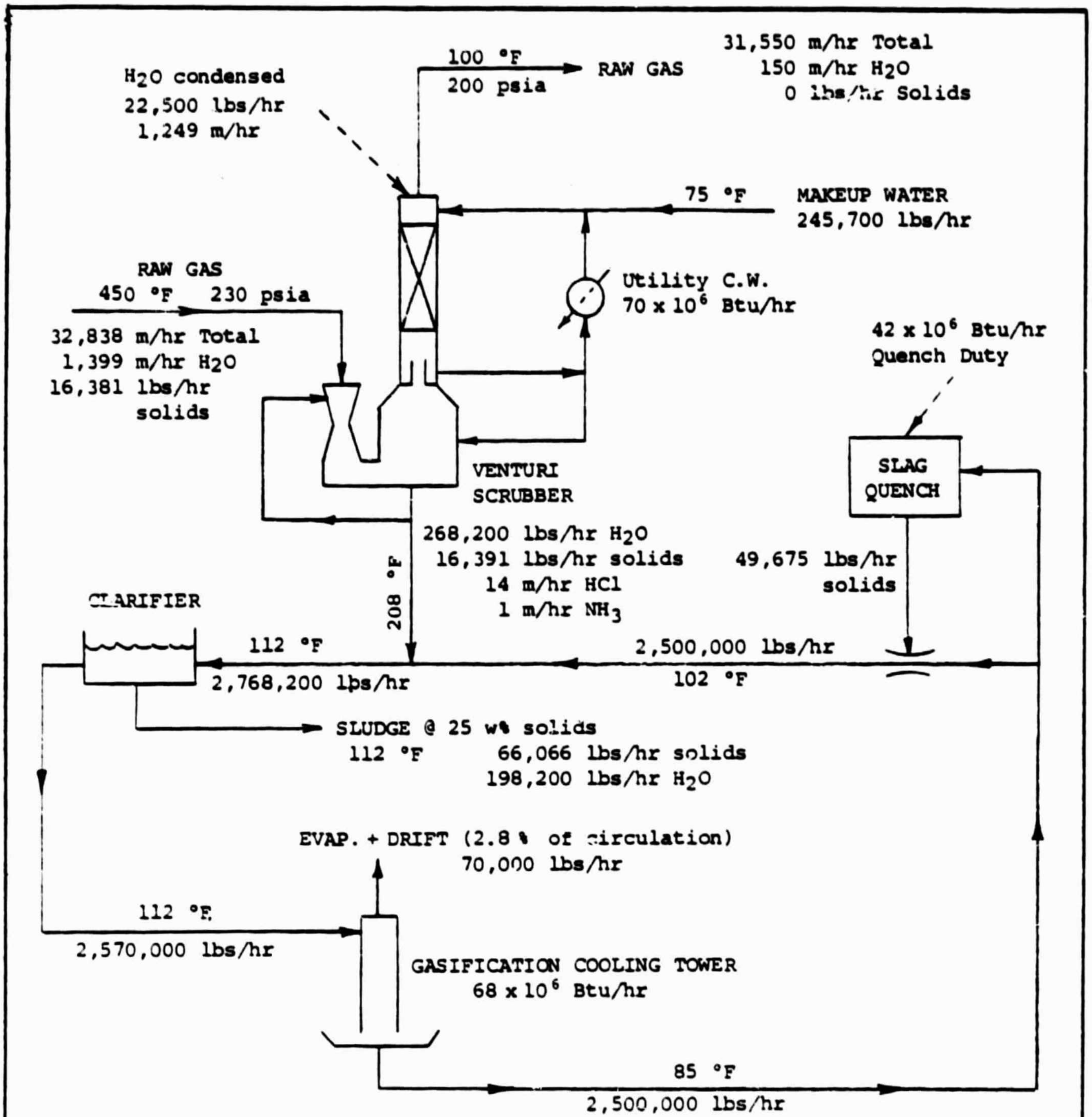
4.1.4.2 Discussion of Process Design Elements

The slag quenching and sluice water rate was taken to be 2,500,000 lbs/hr (5,000 gpm) from the B&W design. The water incurs a 17°F temperature rise in absorbing the 42 million Btu/hr duty required to quench and cool the gasifier slag from 3,000°F to 100°F.

The residual char removed from the raw gas in the Venturi scrubber amounts to 16,381 lbs/hr, which exits with the water leaving the bottom of the scrubber. That water joins the slag sluice water containing 49,675 lbs/hr of the quenched and shattered slag. Thus, the total solids to be removed in the clarifier amounts to 66,066 lbs/hr. Assuming that the sludge from the clarifier is 25 wt percent water, the sludge contains 198,200 lbs/hr of water (the cooling system blowdown) and 66,066 lbs/hr of solids.

The evaporation and drift loss from the cooling tower will be 1 percent of the circulating water rate for each 10°F of cooling across the tower. The drift loss may be taken as 0.1 percent of the circulating water rate. Thus, the evaporation and drift loss from the tower will be 2.8 wt percent of the circulating water rate of 2,500,000 lbs/hr for 27°F cooling across the cooling tower. The evaporation and drift, therefore, amounts to 70,000 lbs/hr. The total makeup required to the system is the sum of the blowdown plus the evaporation and drift, which amounts to 268,200 lbs/hr of water to be derived from the bottom of the Venturi scrubber. Since 22,500 lbs/hr of that amount is derived from condensing water in the Venturi scrubber, the net makeup to the Venturi scrubber must be 245,700 lbs/hr. Setting two conditions that (1) the bottoms water from the Venturi scrubber must not exceed its atmospheric boiling point of 212°F and (2) that the cooling duty not removed by the makeup water will be removed by a circulating sidestream cooler, a heat balance around the Venturi scrubber determined the bottoms temperature of 208°F and the sidestream cooling duty of 70 million Btu/hr. Finally, the mixture of slag sluice water at 102°F and the Venturi bottoms water at 208°F amounts to 2,768,200 lbs/hr of water entering the clarifier at 112°F. The rest of the material and heat balances on the water loop diagram simply involve the appropriate arithmetic.

One item of the above described design still requires some further study. The amount of hydrogen sulfide that will be absorbed in the Venturi scrubber (from the raw gas) and that will remain in the bottoms water at 208°F must be very carefully determined. Since the Venturi bottoms water contain more hydrochloric acid than ammonia, the ammonia will be tied up by the acid and will not be available for tieing up any hydrogen sulfide in the water. Thus, unless the ash and char solids in the water have enough basicity to tie up the hydrogen sulfide, the hydrogen sulfide will be present in the free gaseous state. When that free hydrogen sulfide enters the gasification cooling tower, it will be stripped to the atmosphere with the evaporation and will very probably constitute an environmental problem. If further study indicates that such a problem exists, it may be



Water In:	Water Out:
245,700	198,200
22,500	70,000
268,200	268,200

	10^6 Btu/Hr
Raw Gas (in - out)	104.0
Slag Quench	42.0
	146.0
Utility C. Twr.	70.0
Gasif. C. Twr.	68.0
Sludge Water	7.3
	145.3

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5.2.4

GASIFICATION WATER LOOP BABCOCK & WILCOX

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necessary to provide a stripper on the bottoms water from the Venturi scrubber to remove any hydrogen sulfide and to route the hydrogen sulfide into the sulfur recovery plant.

4.1.5 System 6 - Air Separation

The air separation plant is designed to provide 3,850 short tons/day of 98 percent oxygen for use in the gasification section.

About 1,484,000 lbs/hr of atmospheric air is compressed, in two stages of compression, to a pressure of 110 psia and aftercooled to 100^{o}F. The compressed air is then cryogenically separated into oxygen and nitrogen in a packaged 'cold box'. The separated oxygen from the cold box (at 2 psig and 70^{o}F) is compressed, in four stages of compression, to 290 psia for use in the gasifiers.

A part of the separated nitrogen (about 34,600 lbs/hr at 2 psig and 70^{o}F) is compressed, in four stages of compression, to 295 psia for use in pressurizing the gasifier coal feed system and in transporting coal into the gasifiers.

Interstage cooling down to 150^{o}F is provided by air-cooling. After-cooling for the compressed air, oxygen and nitrogen is provided by air-cooling down to about 120^{o}F and by water-cooling down to 100^{o}F. The compressed oxygen and nitrogen inputs to the gasification section were aftercooled to 100^{o}F because the B&W design so indicated. However, it would be worth investigating the feasibility of deleting the oxygen and nitrogen aftercoolers. That would provide an additional 20 million Btu/hr of heat input to the gasifiers, making it possible to generate about an additional 20,000 lbs/hr of steam. As discussed in the steam balance section herein, that would be desirable.

The air separation plant was designed as two trains, each in operating service and each providing 1,925 tons/day of oxygen. HOWEVER, ALL OF THE QUANTITIES REFERRED TO IN THIS DISCUSSION ARE FOR THE FULL 3,850 TONS/DAY OF OXYGEN OUTPUT.

4.1.6 System 7 - Raw Gas Compression

The raw gas from the Venturi scrubber (666,000 lbs/hr at 100^{o}F and 200 psia) is compressed, in two stages of compression, to 640 psia and aftercooled to 100^{o}F for processing through the acid gas removal system (Selexol unit).

Interstage cooling down to 130^{o}F is provided by air-cooling. After-cooling is provided by air-cooling down to 120^{o}F and by water-cooling down to 100^{o}F.

The raw gas compression train was designed as a single, operating train with no standby train.

SUMMARY OF COMPRESSION

Table 4.1 presents a detailed summary of the compression requirements for the 5,000 T/D coal gasification module, which may be summarized as:

Air compression	72,700 HP
Oxygen compression	19,200 HP
Nitrogen compression	2,430 HP
Raw Gas compression	23,000 HP

For the purposes of the steam balance later herein, it was assumed that (1) the air and oxygen total compression requirement of 91,900 HP could be reduced to 88,000 HP and (2) the raw gas compression could be reduced to 20,800 HP in a final, optimized plant design.

As shown in the steam balance section herein, all of the compressors are driven by steam turbines. The air, oxygen and raw gas compressors are also provided with standby motors for use during plant startup before steam becomes fully available.

4.1.7 System 4 - Acid Gas Removal System

The acid gas removal system utilizes the Selexol solvent process and receives 666,000 lbs/hr of sour gas at 100°F and 635 psia. The sweet (desulfurized) gas leaves the Selexol absorber at about 630 psia and a maximum temperature of 75°F. The component removals across the absorber are:

	Inlet Gas (mols/hr)	Outlet Gas (mols/hr)	% Removal
Hydrogen	9,275.5	9,271.5	0.04
Carbon monoxide	19,115.1	19,110.1	0.03
Carbon dioxide	1,437.1	771.8	46.29
Hydrogen sulfide	451.5	0.2	99.96
Carbonyl sulfide	30.9	0.5	98.38
Nitrogen	1,030.2	1,030.2	0.00
Water	45.5	4.5	90.11
	31,385.8	30,188.8	

The Selexol unit includes an absorption refrigeration unit for chilling the lean solvent so as to achieve the above removals of hydrogen sulfide and carbonyl sulfide. The sour gas from the Selexol unit is rich in CO_2 and at slightly more than atmospheric pressure.

TABLE 4.1. SUMMARY OF COMPRESSOR HORSEPOWERS

	GAS LBS/HR	GAS MOL WT	P_s psia	P_d psia	T_s °F	T_d °F	HORSEPOWER[a]
OXYGEN COMPRESSOR:							
1st Stage	314,000	32	16.4	35.6	70	240	4,517
2nd Stage	314,000	32	33.6	70.0	150	338	4,893
3rd Stage	314,000	32	68.0	141.0	150	337	4,858
4th Stage	314,000	32	139.0	292.0	150	340	4,954
						TOTAL	19,222[b]
AIR COMPRESSOR:							
1st Stage	1,484.000	28.7	14.2	43.0	70	335	35,710
2nd Stage	1,484.000	28.7	40.0	110.0	150	423	36,987
						TOTAL	72,697[b]
RAW GAS COMPRESSOR:							
1st Stage	666,000	21.2	200.0	356.0	100	232	11,025
2nd Stage	666,000	21.2	354.0	640.0	130	273	11,956
						TOTAL	22,981[b]
INERT GAS COMPRESSOR:							
1st Stage	34,608	28	16.4	36.0	70	247	577
2nd Stage	34,608	28	34.0	72.0	150	342	631
3rd Stage	34,608	28	70.0	146.0	150	338	617
4th Stage	34,608	28	144.0	297.0	150	335	606
						TOTAL	2,431

NOTES:

[a] All calculated as adiabatic compression, using:

$k = 1.4$ (c_p/c_v)

$z_m = 1.0$ (compressibility factor)

$e_a = 0.78$ (adiabatic efficiency)

[b] For use in steam balance, these were reduced by 5 to 10 percent on the assumption that an optimized design could achieve such reductions.

4.1.8 System 5 - Sulfur Recovery & Tail Gas Treatment

Acid gas from Acid Gas Removal, System 4, is fed to a Claus-type three-stage sulfur recovery unit utilizing a proprietary process for handling lean H_2S acid gases. Typically in a Claus type sulfur plant, the acid gas is first passed through a knockout drum before entering the reaction furnace. The chemistry of the process involves converting H_2S to elemental sulfur according to the following equation:

$$2H_2S + SO_2 \longrightarrow 3S + 2H_2O$$

Any hydrocarbons in the acid gas are burned to CO_2 and H_2O. System 5 is shown schematically in Drawing Number 524-BW-04.

The reactions are exothermic, and the heat liberated generates steam in the reaction furnace boiler and in the sulfur condenser. The sulfur from each condenser is drained to a recovery pit in Byproduct Processing, System 13 and the tail gas from the final condenser is fed to a Beavon tail gas treating unit where essentially complete removal of the remaining sulfur compounds is achieved before discharge to the atmosphere. The Beavon sulfur removal process is capable of reducing the sulfur content in the tail gas to less than 100 ppm. It is proprietary process. In this system hydrogenation and hydrolysis are used to convert essentially all sulfur compounds to hydrogen sulfide. This gas is then cooled, and passed into a contactor where the hydrogen sulfide is absorbed by the redox solution and oxidized to elemental sulfur. The reduced redox solution is reoxidized by contact with air and subsequently recirculated to the contactor. Elemental sulfur is removed in the air-blowing step as a froth which is pumped to a sulfur melter to be melted under pressure, separated from the redox solution, and transferred to Byproduct Processing, System 13. The decanted redox solution is returned to the system.

The chemical reactions are:

<u>Hydrogenation and Hydrolysis</u>

$$SO_2 + 3H_2 \longrightarrow H_2S + 2H_2O$$

$$S + H_2 \longrightarrow H_2S$$

$$COS + H_2O \longrightarrow H_2S + CO_2$$

$$CS_2 + 2H_2O \longrightarrow 2H_2S + CO_2$$

The system receives 48,370 lbs/hr of acid gas from the Selexol solvent regenerator at about 7 psig and 120°F. The inlet gas composition is:

	Inlet Gas (mols/hr)
Hydrogen	4.0
Carbon monoxide	5.0
Carbon dioxide	665.3
Hydrogen sulfide	451.3
Carbonyl sulfide	30.3
Nitrogen	0.0
Water	99.2
	1,255.1

The recovery of byproduct elemental sulfur from the sulfur recovery system is 185 short tons/day, which amounts to an overall sulfur recovery of about 99.9 percent.

4.1.9 System 13 - By-Product Processing

Sulfur is the only plant byproduct other than ash/char solids which are disposed of on site. Molten sulfur is pumped to a prilling tower in a continuously flowing circulation system. In the tower sulfur is dispensed in droplets through nozzles. Droplets fall counter current to a stream of cooling air and solidify prior to landing in the bottom prill collection section. From the prill tower sulfur is conveyed to a storage building from which it is transferred by truck or barge for sale. Drawing Number 524-BW-08 shows this schematically.

4.1.10 System 14 - Plant Power System

This system is generally designed to receive medium voltage electrical power (4.16 KV, 6.9 KV or 13.8 KV) and provide the following functions:

- Develop the necessary voltage stepdown arrangement for plant requirements
- Distribute the necessary power to the plant equipment.

This is non-proprietary equipment and is supplied by several U.S. vendors.

TVA's incoming substation transformers receive power from its prevalent distributed voltage switching station and step down this voltage to a medium voltage to supply the plant electrical power requirement for motors, heaters, lighting, and other miscellaneous loads.

The Medium Voltage Electrical Distribution System is a secondary selective system (double ended supply) with several medium voltage buses. Each medium voltage bus receives power from its respective incoming substation transformer through an incoming breaker and supplies power to the medium voltage distribution system through the feeder breakers.

The Low Voltage Electrical Distribution System typically consists of multiple 480 V double ended load centers and 480 V motor control centers (MCC's) supplying the power to 480 V loads throughout the plant. Two load centers are interconnected through a normally open tie breaker. In the event of loss of one load center transformer or its feeder, the 480 V loads of the affected load center are fed by the second load center through the tie breaker.

Each load center consists of an incoming line section, load center transformer, and low voltage section with metal enclosed draw out power circuit breakers.

Load center transformers are air cooled, dry type, 150^{o}F temperature rise, with delta connected primaries and wye connected secondaries. All load center feeder circuit breakers are 1600A frame and 50,000A RMS symmetrical interrupting capacity. The 480 V motor feeder breakers are electrically operated with instantaneous and long time trip units.

480 V MCC's consist of starters, feeder circuit breakers and control devices, assembled in a common structure with horizontal and vertical buses.

A 125 Volt DC System supplies control power for medium voltage and 480 V volt plant switchgear control, protective relaying and annuciation. The system also supplies power for emergency lighting.

4.1.11 System 15 -Steam Generation/Distribution

A steam balance diagram is included in Section 6, Drawing Number 524-BW-10. As shown on that diagram, two of the largest steam demands within the plant are for the steam turbine drives of the air and oxygen compressors in the air separation plant. Since the coal gasifiers are the largest source of heat for generating steam within the plant, it was decided to produce 565 psia steam from the gasifiers and to drive the air and oxygen compressor turbines with that steam. In order to match the 565 psia steam supply (512,700 lbs/hr) with the horsepower demand of the air and oxygen compressors, it was necessary to superheat the steam to 1000^{o}F and to condense the turbine exhausts at 2.5" Hg and 109^{o}F.

The gasification section waste heat boilers were designed to produce 352,100 lbs/hr of 1500 psia steam to be used as follows:

Char recycle transport	32,700 lbs/hr
Sulfur plant (Claus gas reheaters)	20,000 lbs/hr
Raw Gas compressor turbine	299,400 lbs/hr
Total	352,100 lbs/hr

The 299,400 lbs/hr of 1500 psia steam for the raw gas compressor turbine is superheated to 940^{o}F so that the turbine exhaust would produce 165 psia steam for driving the irert gas (nitrogen) compressor turbine and for supplying other users at that pressure or lower.

The steam balance is very tight. The deaerator is 'out of balance' heatwise by about 13 million Btu/hr or 6.7 percent. That is, the heat entering the deaerator is 6.7 percent (13 million Btu/hr) less than the heat leaving the deaerator, which means that the boiler feedwater temperature will be somewhat lower than the 250^{o}F shown on the steam balance diagram.

At the same time, from the viewpoint of protection against power failures, it would be desirable to drive the boiler feedwater pumps (1500 HP) and at least some of the cooling water circulation pumps (5700 HP) with steam turbines rather than electric motors.

Since the steam balance is about 13 million Btu/hr deficient, and since it would be desirable to drive the boiler feedwater and some of the cooling water pumps with steam turbines, it is apparent that more steam must be made available.

There are a number of options to be explored for making more steam available:

1 -- As mentioned earlier in this report, deleting the after-cooling of the compressed oxygen fed to the gasifiers would make about 20 million Btu/hr of more steam available from the gasifiers.

2 -- Designing the gasification section waste heat boilers to cool the raw gas down to 400^{o}F (instead of 450^{o}F) would make about 13 million But/hr of more steam available from the waste heat boilers.

3 -- Using boiler feedwater to cool the primary cyclone recycle char from 1800^{o}F dowr to 1200^{o}F (instead of cooling water) would provide another 25 million Btu/hr.

4 -- Re-designing the Claus unit to use internal gas-to-gas reheat, or gasified reheat, instead of steam reheat would make another 20,000 lbs/hr of steam available.

5 -- Superheating the 1500 psia steam to $1000^{o}F$ (instead of $940^{o}F$) would reduce the consumption of steam required to drive the raw gas compressor.

6 -- It would be worth investigating if $1000^{o}F$ steam temperature for turbine drive steam is the upper limit of current practice.

7 -- Although the exhausting of condensing turbines at 2.5" Hg and $108^{o}F$ is probably as low as can be economically justified with $85^{o}F$ cooling water, it would be worth investigating the feasibility of 2" Hg and $102^{o}F$.

8 -- As mentioned earlier in this report, the preliminary steam balance already assumes that the calculated compression horsepower for the air, oxygen and raw gas compressors could be reduced by 5-10% in a final optimized design. That remains to be confirmed or to determine if larger reductions can be achieved.

The above options should readily provide enough additional steam to close the deaerator heat balance and to drive the boiler feedwater pumps with steam turbines. Additional studies are required to determine if additional steam can be made available for driving some of the cooling water pumps with steam turbines.

4.1.12 System 16 - Water Supply

The Raw Water Treatment Unit is designed to provide treated and untreated water for the following facility water systems:

Fire Water
Service Water
Potable Water
Cooling Water
Boiler Feedwater

Raw water is pumped from the river to a Fire Water-Raw Water Storage tank.

The Raw Water-Firewater Storage Tank provides surge capacity for Water Treatment as well as storage capacity for firewater. During an emergency, firewater is pumped from the tank to the firewater header system. The firewater pumps are motor driven and have a diesel engine driven spare. The spare pump is equipped with automatic start-up capability in case of power failure.

The raw water is pumped from the Raw Water-Firewater Storage Tank to the Softener-Clarifier. Lime, alum, and polyelectrolyte from the Clarifier Bulk Chemical Storage and Feed System are added to the Softener-Clarifier, which is equipped with an internal flocculation mechanism. The alum and polyelectrolyte aid in the removal of suspended solids from the raw water. Lime is added during the clarification step to "cold soften" the raw water. Chlorine is added to the raw water to inhibit algae growth in the clarifier and sand filters and reduce organic contamination.

The underflow from the clarifier is a one wt percent sludge and is pumped to solids treatment for further processing.

The clarified and softened raw water from the Softener-Clarifier flows to the Self-Backwashing Sandfilters where additional suspended solids are removed. A pressure differential across the filter bed initiates the backwash cycle. The backwash flows by gravity to the Sandfilter Backwash Sump and is recycled to the Softener-Clarifier. The filtered water flows to the Filtered Water Storage Tank and is utilized as cooling tower make-up for the Process Cooling Tower as service water for general plant use, as feed to the Demineralizer Package, and as feed to the potable water system.

Water intended for potable services is chlorinated and again filtered to meet American Water Works Association (AWWA) standards and stored in a tank sized to hold a day's potable water requirements. The chlorine residual is maintained at 0.5-1.0 PPM free chlorine in the tank.

Filtered water intended as feed to the Demineralizer Package is injected with Sodium Sulfide to remove trace amounts of chlorine which adversely affect the Demineralizer resins and after filtered through activated carbon to remove any remaining organic contaminants and dissolve iron.

In the demineralizer, the mineral salts present in the water are removed by ion exchange. A two-step demineralization system, utilizing strong cation and strong anion exchangers in series, is provided. A degasifier following the strong cation and magnesium, which the anion exchangers remove anions such as chloride and sulfate. The strong anion exchanger also removes silica. The degasifier is provided to remove carbon dioxide and other dissolved gases.

A mixed bed polisher is provided to remove silica to 0.02 PPM and to polish returned turbine condensate for reuse.

The demineralized water and condensate is preheated to 220-225^{O}F before being pumped into the boiler feedwater deaerators.

Acid, stored in the Acid Tank, is used to regenerate the cation exchangers. Caustic, stored in the Caustic Tank, is used to regenerate the anion exchangers.

Both the Acid and Caustic tanks have pumps and metering devices to control the flow of regenerants to the demineralizer package.

The Boiler Feedwater Deaerating heaters operate at 30 psig and 250^{o}F. The Deaerators reduce the oxygen content of BFW to 0.005 cc/liter.

Hydrazine or sodium sulfite is injected into the storage compartment of the deaerators for chemical scavenging of any residual oxygen. Morpholine is injected into the suction of the boiler feed-water pumps to protect the condensate systems.

A tabulated water balance for the overall plant is given in Table 4.2 at the end of this section. The total raw water intake required, including an appropriate contingency, amounts to 3,500 gpm.

4.1.13 System 17 - Water Cooling

The purpose of this unit is to provide cooling water to the various process users in the facility.

This is a non-proprietary system and is supplied by several US vendors. System 17 is shown schematically in Drawing Number 524-BW-12.

The cooling tower system includes the tower and fans, sidestream filters, circulating water pumps, cold water basin, blowdown system, chemical addition equipment, and distribution system.

Cooling water is pumped from the cold water basin, through the distribution system to the process heat exchangers where low-level, sensible heat is picked up, and back to the cooling tower. The cooling tower rejects low-level heat by evaporative cooling to air drawn through the cooling tower by the cooling tower fans.

A portion of the circulating water is passed through side stream filters to reduce loading to suspended solids, dirt and scale.

The dissolved solids level of the cooling water is maintained by a continuous blowdown stream to the process condensate system. Water level in the cooling tower basis is maintained by continuous make up of the clean water from the raw water treatment system.

The blowdown stream is passed through a blowdown treatment system to recover chromate ions via ion exchange or by chemical reduction to chromium hydroxide and is sent to waste treatment for disposal.

TABLE 4.2. OVERALL WATER BALANCE[a]

	GPM
INPUTS:	
Makeup to boiler feedwater (BFW)	114
Makeup to gasification cooling tower[b]	491
Makeup to utility cooling tower	2,357
Raw water treatment makeup[c]	148
TOTAL RAW WATER REQUIRED	3,110[f]
OUTPUTS:	
Gasification cooling tower evaporation and drift	140
Utility cooling tower evaporation and drift	1,886
Gasification cooling tower blowdown (BD)[d]	396[e]
Boiler blowdown (BD)	47[e]
Deaerator vent	2
Raw water treatment wastewater[c]	148[e]
Steam into process:	
Into gasifiers via char eductor	65
Recovered by condensation in Venturi scrubber	-45
Utility cooling tower blowdown (BD)	471
TOTAL OUTPUTS	3,110

NOTES:

[a] Excluding the water contained in the feed coal

[b] Fed into Venturi scrubber (see diagram of gasification water loop)

[c] Rinse waters and other wastage

[d] Contained in sludge to disposal (see diagram of gasification water loop)

[e] Wastewater streams for disposal

[f] The total raw water demand is estimated to be 3,500 gpm, including an allowance of 390 gpm for utility water and contingency.

Chlorine is added to the cooling water on a routine periodic basis to prevent algae growth. Chemical algicides are added periodically to further eliminate algae growth. Sulfuric acid is added to control pH and zinc and chromate inhibitors are added to the cooling water for corrosion control. Occasionally, a polyphosphate dispersant is added to enhance the action of the inhibitors.

4.1.14 System 18 - Waste Water Treatment

The purpose of this unit is to collect and treat all plant liquid effluent streams. The plant design is predicated on "zero discharge" and permits recycle and reuse of treated water. Streams treated include the following:

- Oily Water Sewers
- Coal Pile Run Off
- Storm Water Run Off
- Demineralizer Regenerant Wastes and Rinse Water
- Cooling Tower Blowdown
- Sanitary Waste Water
- Gasifier Slag Quench Drains
- Separated Water From Solids Treatment
- Filtrate From Biological Treatment.

Process operations include:

OIL SEPARATOR - streams containing free and dissolved oil and treated in a gravity separator utilizing an emulsion breaking chemical and heat to separate the oil-water mixture.

SOUR WATER STRIPPER - water streams with appreciable H_2S or NH_3 residuals are steam stripped to remove these contaminants.

EQUALIZATION BASIN - liquid streams with extremely high or low pH are mixed in an equalizing basin and treated with sulfuric acid or caustic to change the mixed pH to a value of 6.0 - 8.0.

GRAVITY SETTLING-THICKENER - liquid streams with high suspended or dissolved solids are treated in a gravity settler-thickener and mixed with lime, alum, coagulant aids, and polymers to facilitate separation and thickening.

MULTIPLE EFFECT EVAPORATION - neutralized wastes and brines are evaporated to recover water and concentrate the solids.

The recovered, treated water is used as make up to cooling towers or raw water supply. The resultant solids are conveyed to the Solids Disposal System.

4.1.15 System 19 - General Facilities

The purpose of this unit is to provide equipment or services to support the Gasification Facility at the facility level.

The equipment and Services provided in this unit are non-proprietary.

This unit is a general facility category and provides the following equipment and services:

- Administration Building
- Laboratories
- Change Rooms
- Warehouses
- Maintenance Buildings
- Operation Centers
- Security Offices
- Plant Air Facility
- Fire House
- Visitor Reception
- Plant Fencing
- Plant Lighting
- Roads, Bridges
- Docking Facilities
- Interconnection Pipe Ways
- Fire Protection Network
- Flare Stacks and Headers
- Plant Instrument Air Compressors
- Environmental Monitoring
- Site Preparation.

4.2 Module Balances

Material and energy balances have been determined for each module. Table 4.3 gives stream compositions and quantities for each intersystem module. Table 4.4 gives an energy balance at the modular level.

TABLE 4.3
MATERIAL BALANCE
B&W PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			01-1		01-2		1-1	
STREAM ID			RAW COAL FEED		RAW WATER TO WATER TREATMENT		COAL TO GASIFIER	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01		253637				253637
HYDROGEN	H_2	2.016		17925				17925
OXYGEN	O_2	32.0		23900				23900
NITROGEN & ARGON	N_2	28.016		5761				23253
SULFUR	S	32.06		15450				15450
CHLORINE	Cl	35.453		492				492
CARBON MONOXIDE	CO	28.01						
CARBON DIOXIDE	CO_2	44.01						
METHANE	CH_4	16.042						
ETHYLENE	C_2H_4	28.052						
ETHANE	C_2H_6	30.068						
PROPYLENE	C_3H_6	42.078						
PROPANE	C_3H_8	44.094						
HYDROGEN SULFIDE	H_2S	34.076						
CARBONYL SULFIDE	COS	60.075						
CARBON DISULFIDE	CS_2	76.13						
SULFUR DIOXIDE	SO_2	64.06						
NITROUS OXIDE	NO_2	30.008						
AMMONIA	NH_3	17.031						
HYDROGEN CYANIDE	HCN	27.026						
HYDROGEN CHLORIDE	HCl	36.461						
NAPHTHA	-							
TAR & OIL	-							
ASH	-			59650				59650
OTHER SOLIDS								
SUBTOTAL, DRY				376817				394307
WATER	H_2O	18.016		39850				7693
TOTAL, WET				416667				402000
GAS MOLECULAR WEIGHT								
TEMPERATURE, °F								100
PRESSURE, PSIA								290
SCFH								
GPM						3500		

TABLE 4.3 (Continued)
MATERIAL BALANCE
B&W PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			1-2		2-1		2-2	
STREAM ID			VENT GAS FROM COAL PREPARATION AND FEEDING		RAW GAS FROM GASIFIER		ASH TO SOLIDS TREATMENT	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01						
HYDROGEN	H_2	2.016			9275.5	18699		
OXYGEN	O_2	32.0	4302.2	137670				
NITROGEN & ARGON	N_2	28.016	18062.3	506040	1030.2	31252		
SULFUR	S	32.06						
CHLORINE	Cl	35.453						
CARBON MONOXIDE	CO	28.01			19115.1	535414		
CARBON DIOXIDE	CO_2	44.01	364.9	16060	1437.1	63258		
METHANE	CH_4	16.042						
ETHYLENE	C_2H_4	28.052						
ETHANE	C_2H_6	30.068						
PROPYLENE	C_3H_6	42.078						
PROPANE	C_3H_8	44.094						
HYDROGEN SULFIDE	H_2S	34.076			451.5	15385		
CARBONYL SULFIDE	COS	60.075			30.9	1829		
CARBON DISULFIDE	CS_2	76.13						
SULFUR DIOXIDE	SO_2	64.06						
NITROUS OXIDE	NO	30.008						
AMMONIA	NH_3	17.031			0.9	16		
HYDROGEN CYANIDE	HCN	27.026						
HYDROGEN CHLORIDE	HCl	36.461			13.9	506		
NAPHTHA	-							
TAR & OIL	-							
ASH	-					112864		59650
OTHER SOLIDS						51508		6442
SUBTOTAL, DRY			22729.4	659770	31354.6	830731		66092
WATER	H_2O	18.016	2449.6	44132	1398.2	25190		198606
TOTAL, WET			25179.0	703902	32752.8	855921		264699
GAS MOLECULAR WEIGHT			27.96		21.11			
TEMPERATURE, °F			150		1800			
PRESSURE, PSIA			ATM.		240			
SCFH			9555431		12435113			
GPM								

TABLE 4.3 (Continued)
MATERIAL BALANCE
B&W PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			4-1		4-2		4-3	
STREAM ID			MBG GAS PRODUCT		MBG GAS INTERNAL CONSUMPTION		ACID GAS TO SULFUR RECOVERY	
	SYMBOL	FORMULA WEIGHT	LB-MOLS / HR	LBS / HR	LB-MOLS / HR	LBS / HR	LB-MOLS / HR	LBS / HR
CARBON	C	12.01						
HYDROGEN	H_2	2.016	8241.0	16614	1030.0	2077	4.0	8
OXYGEN	O_2	32.0						
NITROGEN & ARGON	N_2	28.016	915.7	27779	114.5	3473		
SULFUR	S	32.06						
CHLORINE	Cl	35.453						
CARBON MONOXIDE	CO	28.01	16986.0	455779	2124.1	59496	5.0	140
CARBON DIOXIDE	CO_2	44.01	686.0	30191	85.8	3776	665.3	29280
METHANE	CH_4	16.042						
ETHYLENE	C_2H_4	28.052						
ETHANE	C_2H_6	30.068						
PROPYLENE	C_3H_6	42.078						
PROPANE	C_3H_8	44.094						
HYDROGEN SULFIDE	H_2S	34.076	.117	6	.023	1	451.3	15378
CARBONYL SULFIDE	COS	60.075	.533	32	.007	4	29.8	1790
CARBON DISULFIDE	CS_2	76.13						
SULFUR DIOXIDE	SO_2	64.06						
NITROUS OXIDE	NO	30.008						
AMMONIA	NH_3	17.031						
HYDROGEN CYANIDE	HCN	27.026						
HYDROGEN CHLORIDE	HCl	36.461						
NAPHTHA	-							
TAR & OIL	-							
ASH	-							
OTHER SOLIDS								
SUBTOTAL, DRY			26829.0	550401	3355.0	68827	1155.4	46596
WATER	H_2O	18.016	3.9	70	4.7	85	3.0	54
TOTAL, WET			26832.9	550471	3359.7	68912	1158.4	46650
GAS MOLECULAR WEIGHT			20.51		20.51		40.27	
TEMPERATURE, °F			60		60		120	
PRESSURE, PSIA			615		615		645	
SCFH			10183086		1275006		439805	
GPM								

TABLE 4.3(Continued)
MATERIAL BALANCE
B&W PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			5-1		6-1		7-1	
STREAM ID			TAIL GAS FROM SULFUR RECOVERY		OXIDANT TO GASIFIER		SOUR GAS TO ACID GAS REMOVAL	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01						
HYDROGEN	H_2	2.016					9275.5	18699
OXYGEN	O_2	32.0			9841.4	314914		
NITROGEN & ARGON	N_2	28.016	1330.0	37261	200.8	8012	1030.2	31252
SULFUR	S	32.06						
CHLORINE	Cl	35.453						
CARBON MONOXIDE	CO	28.01					19115.1	535414
CARBON DIOXIDE	CO_2	44.01	609.0	26802			1437.1	63250
METHANE	CH_4	16.042						
ETHYLENE	C_2H_4	28.052						
ETHANE	C_2H_6	30.068						
PROPYLENE	C_3H_6	42.078						
PROPANE	C_3H_8	44.094						
HYDROGEN SULFIDE	H_2S	34.076	.0023	.078			451.5	15385
CARBONYL SULFIDE	COS	60.075					30.9	1829
CARBON DISULFIDE	CS_2	76.13						
SULFUR DIOXIDE	SO_2	64.06						
NITROUS OXIDE	NO	30.008						
AMMONIA	NH_3	17.031						
HYDROGEN CYANIDE	HCN	27.026						
HYDROGEN CHLORIDE	HCl	36.461						
NAPHTHA	-							
TAR & OIL	-							
ASH	-							
OTHER SOLIDS								
SUBTOTAL, DRY			1939.0	64063	10042.2	322926	31339.8	665837
WATER	H_2O	18.016	134	2414			45.5	820
TOTAL, WET			2073	66477	10042.2	322926	31385.3	666657
GAS MOLECULAR WEIGHT			32.1		32.16		21.24	
TEMPERATURE, °F			100		77		100	
PRESSURE, PSIA			14.7		240		655	
SCFH			786837		3012678		11915920	
GPM								

TABLE 4.3 (Continued)
MATERIAL BALANCE
EAW PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			8-1		11-1		13-1	
STREAM ID			SOLIDS TO DISPOSAL		COAL PREPARATION AND HANDLING TO COAL		SULFUR TO STORAGE	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01				253632		
HYDROGEN	H_2	2.016				17925		
OXYGEN	O_2	32.0				23900		
NITROGEN & ARGON	N_2	28.016				5761		
SULFUR	S	32.06				15450	481.1	15424
CHLORINE	Cl	35.453				492		
CARBON MONOXIDE	CO	28.01						
CARBON DIOXIDE	CO_2	44.01						
METHANE	CH_4	16.042						
ETHYLENE	C_2H_4	28.052						
ETHANE	C_2H_6	30.068						
PROPYLENE	C_3H_6	42.078						
PROPANE	C_3H_8	44.094						
HYDROGEN SULFIDE	H_2S	34.076						
CARBONYL SULFIDE	COS	60.075						
CARBON DISULFIDE	CS_2	76.13						
SULFUR DIOXIDE	SO_2	64.06						
NITROUS OXIDE	NO_2	30.008						
AMMONIA	NH_3	17.031						
HYDROGEN CYANIDE	HCN	27.026						
HYDROGEN CHLORIDE	HCl	36.461						
NAPHTHA	-							
TAR & OIL	-							
ASH	-			59650		59650		
OTHER SOLIDS				8092				
SUBTOTAL, DRY				67742		376817	481.1	15424
WATER	H_2O	18.016		22581		39850		
TOTAL, WET				90323		416667	481.1	15424
GAS MOLECULAR WEIGHT								
TEMPERATURE, °F							250	
PRESSURE, PSIA								
SCFH								
GPM								

ORIGINAL PAGE IS
OF POOR QUALITY

TABLE 4.3 (Concluded)
MATERIAL BALANCE
B&W PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			16-1		16-2			
STREAM ID			MAKEUP TO COOLING WATER SYSTEM		MAKEUP TO STEAM AND CONDENSATION			
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01						
HYDROGEN	H_2	2.016						
OXYGEN	O_2	32.0						
NITROGEN & ARGON	N_2	28.016						
SULFUR	S	32.06						
CHLORINE	Cl	35.453						
CARBON MONOXIDE	CO	28.01						
CARBON DIOXIDE	CO_2	44.01						
METHANE	CH_4	16.042						
ETHYLENE	C_2H_4	28.052						
ETHANE	C_2H_6	30.068						
PROPYLENE	C_3H_6	42.078						
PROPANE	C_3H_8	44.094						
HYDROGEN SULFIDE	H_2S	34.076						
CARBONYL SULFIDE	COS	60.075						
CARBON DISULFIDE	CS_2	76.13						
SULFUR DIOXIDE	SO_2	64.06						
NITROUS OXIDE	NO	30.008						
AMMONIA	NH_3	17.031						
HYDROGEN CYANIDE	HCN	27.026						
HYDROGEN CHLORIDE	HCl	36.461						
NAPHTHA	-							
TAR & OIL	-							
ASH	-							
OTHER SOLIDS								
SUBTOTAL, DRY								
WATER	H_2O	18.016						
TOTAL, WET								
GAS MOLECULAR WEIGHT								
TEMPERATURE, °F								
PRESSURE, PSIA								
SCFH								
GPM			2848		114			

TABLE 4.4

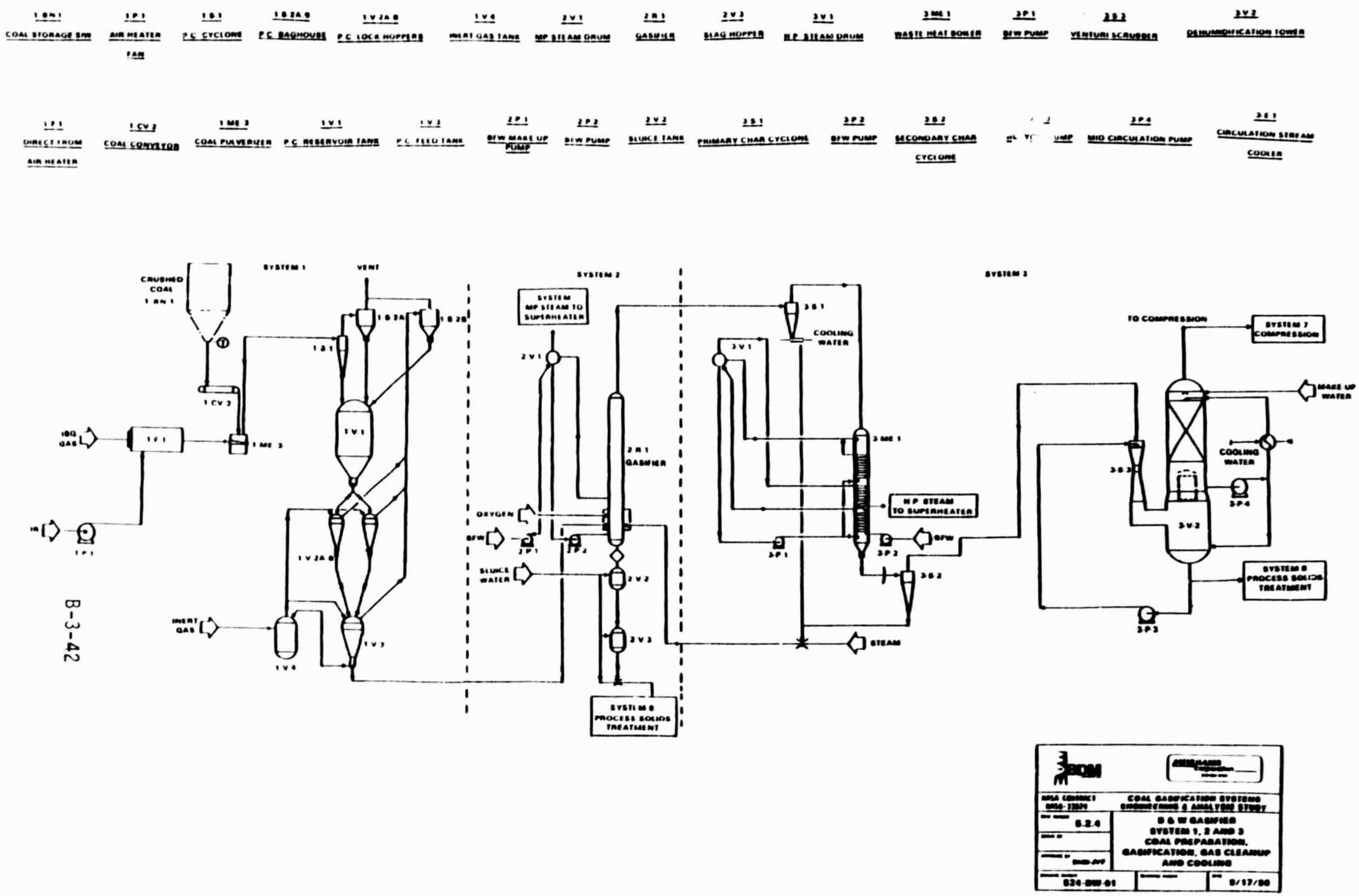
ENERGY BALANCE, 10^6 BTU PER HOUR
BABCOCK & WILCOX PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

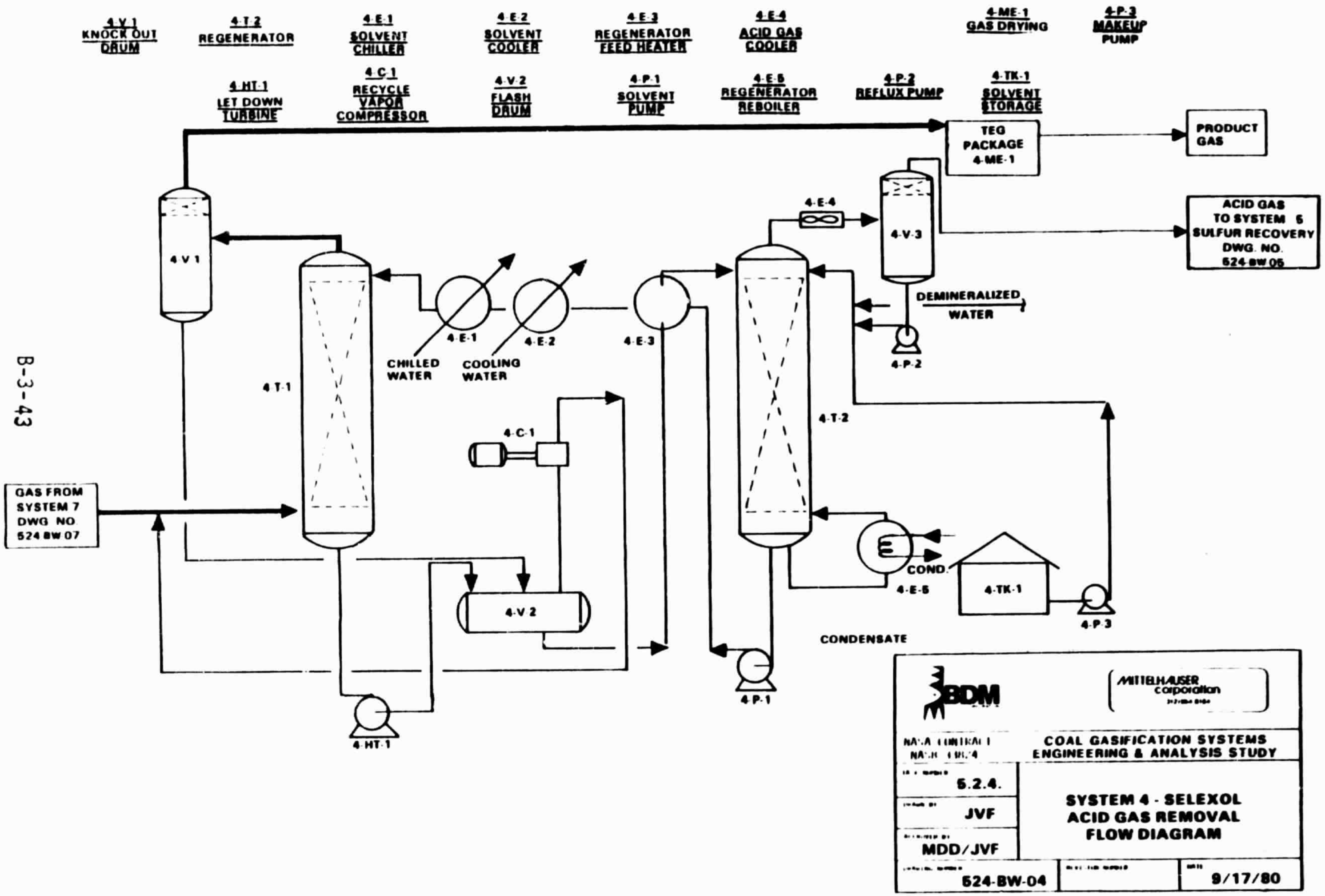
ENTHALPY BALANCE		PHASE	HHV	LATENT	SENSIBLE	TOTAL
INLETS						
STREAM	Coal	Solid	4575	-	-	4575
	Air to Air Sep'n	Gas	-	13.3	-	13.3
	Raw Water	Liquid	-	-	-	0
SUBTOTAL IN						4588.3
OUTLETS						
STREAM	MBG	Gas	3081.4	-	-	3081.4
	Ash	Solid	70.7	-	-	70.7
	Tail Gas	Gas	-	2.6	0.7	3.3
	Sulfur	Solid	61.6	-	0.5	62.1
	Air Sep'n Vent	Gas	-	53.5	16.1	69.6
	Flue Gases	Gas		15.5	45.8	61.3
SUBTOTAL OUT						3348.4
NET INLET-OUTLET						1239.9
HEAT AND SHAFT WORK						
ELECTRIC POWER						19.8
SHAFT WORK						
HEAT REJECTION				-720.1	-476.8	-1196.9
HEAT INPUT (STEAM)						
RADIATION/FUGITIVE LOSS						-25.0
SUBTOTAL NET VALUE						-1202.1
TOTAL ABSOLUTE VALUE						-1202.1

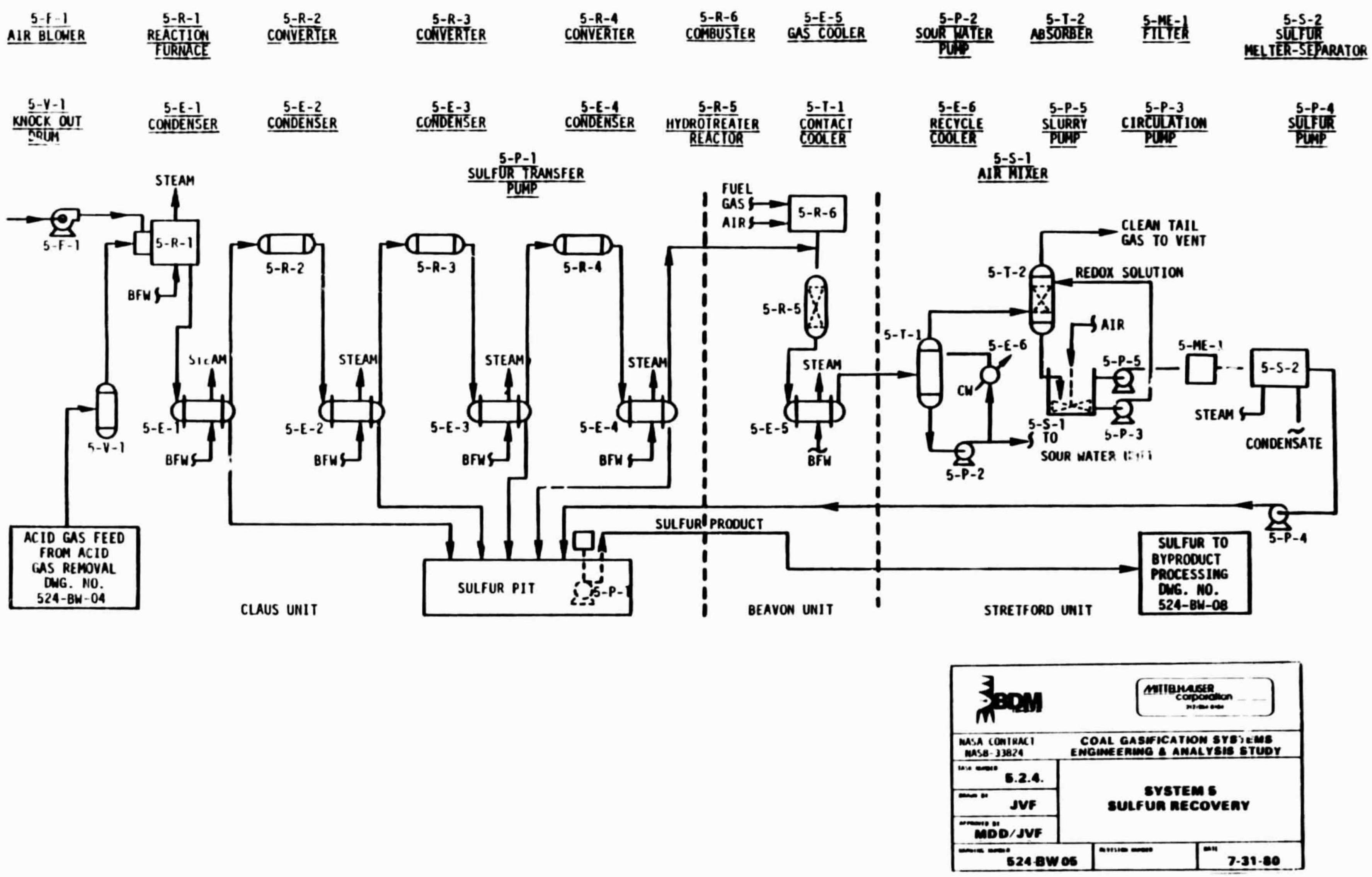
BALANCE: $\dfrac{\text{NET ENTHALPHY + NET HEAT \& SHAFT WORK}}{\text{TOTAL ABSOLUTE VALUE OF HEAT \& SHAFT WORK}} \times 100\% = \dfrac{1239.9 - 1202.1}{1202.1} = 3.2\%$

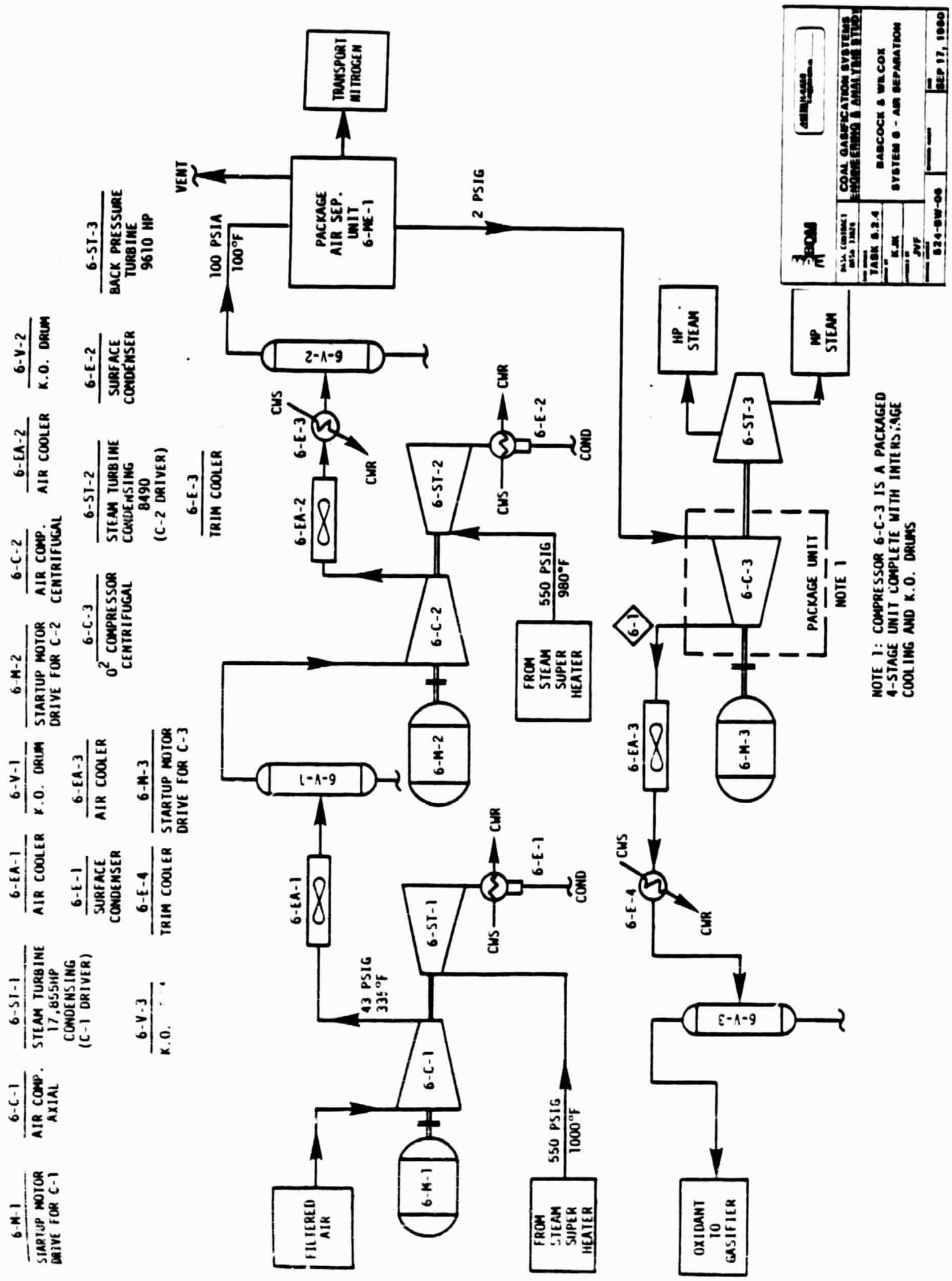
5.0 PROCESS FLOW DIAGRAM AND EQUIPMENT LIST

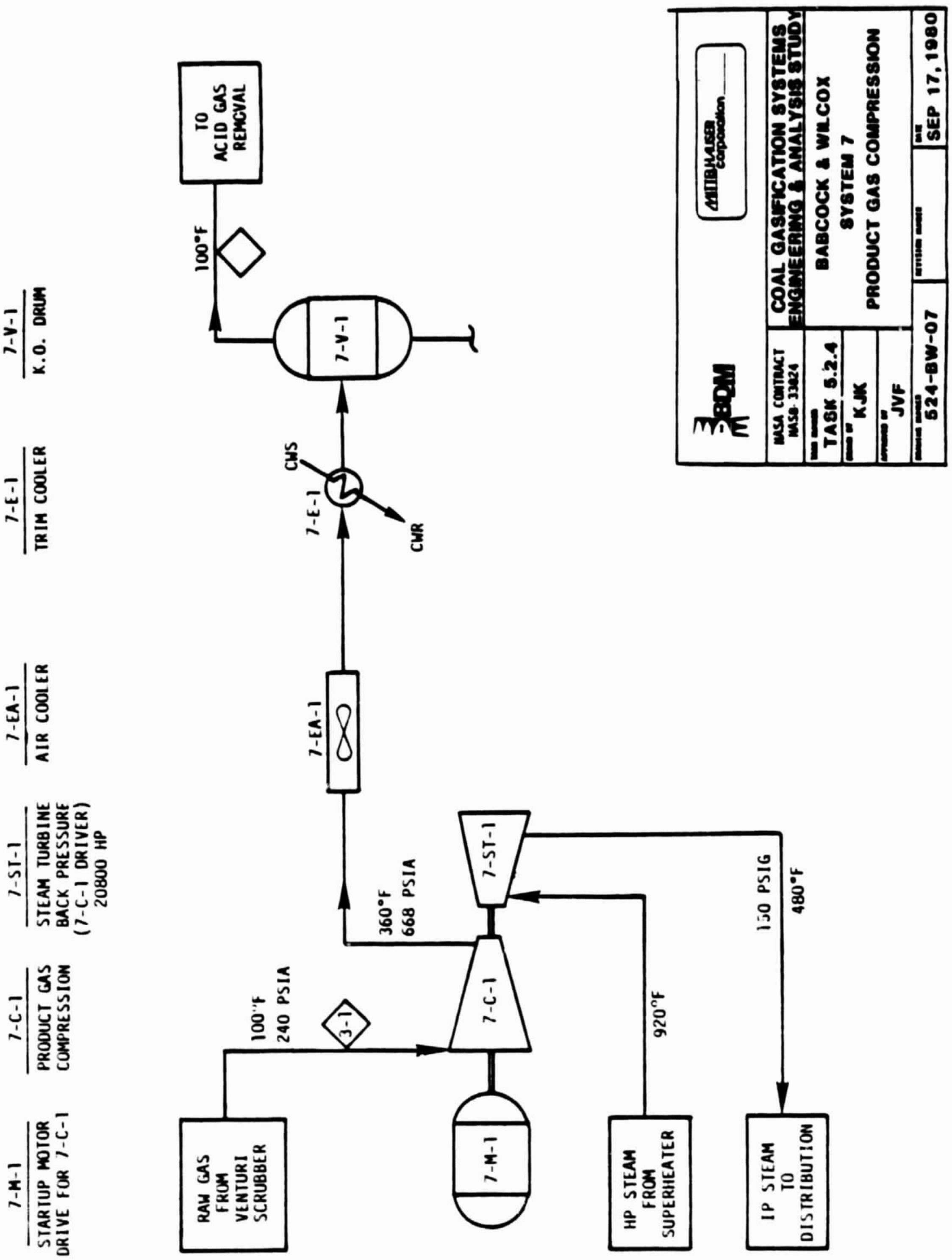
This section contains the process flow diagrams and the list of equipment for each module. The facility contains four times the quantity shown here except for the coal silos which are on a facility basis and System 5, which has two trains in Module 1 and only one train in subsequent modules.


1 BN 1
COAL STORAGE BIN
1 P 1
AIR HEATER FAN
1 S 1
P C CYCLONE
1 S 2A B
P C BAGHOUSE
1 V 2A B
P C LOCK HOPPERS
1 V 4
INERT GAS TANK
2 V 1
MP STEAM DRUM
2 R 1
GASIFIER
2 V 3
SLAG HOPPER
3 V 1
H P STEAM DRUM
3 ME 1
WASTE HEAT BOILER
3 P 1
BFW PUMP
3 S 3
VENTURI SCRUBBER
3 V 2
DEHUMIDIFICATION TOWER
1 F 1
DIRECT FROM AIR HEATER
1 CV 2
COAL CONVEYOR
1 ME 3
COAL PULVERIZER
1 V 1
P C RESERVOIR TANK
1 V 3
P C FEED TANK
2 P 1
BFW MAKE UP PUMP
2 P 2
BFW PUMP
2 V 2
SLUICE TANK
3 S 1
PRIMARY CHAR CYCLONE
3 P 2
BFW PUMP
3 S 2
SECONDARY CHAR CYCLONE
3 P 4
MID CIRCULATION PUMP
3 E 1
CIRCULATION STREAM COOLER
CRUSHED COAL
SYSTEM 1
VENT
SYSTEM 2
SYSTEM 3
ISG GAS
INERT GAS
OXYGEN
BFW
SLUICE WATER
SYSTEM MP STEAM TO SUPERHEATER
2 R 1 GASIFIER
SYSTEM 8 PROCESS SOLIDS TREATMENT
COOLING WATER
H P STEAM TO SUPERHEATER
STEAM
TO COMPRESSION
SYSTEM 7 COMPRESSION
MAKE UP WATER
COOLING WATER
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
6.2.4
B & W GASIFIER
SYSTEM 1, 2 AND 3
COAL PREPARATION, GASIFICATION, GAS CLEANUP AND COOLING
524-BW-01
9/17/80

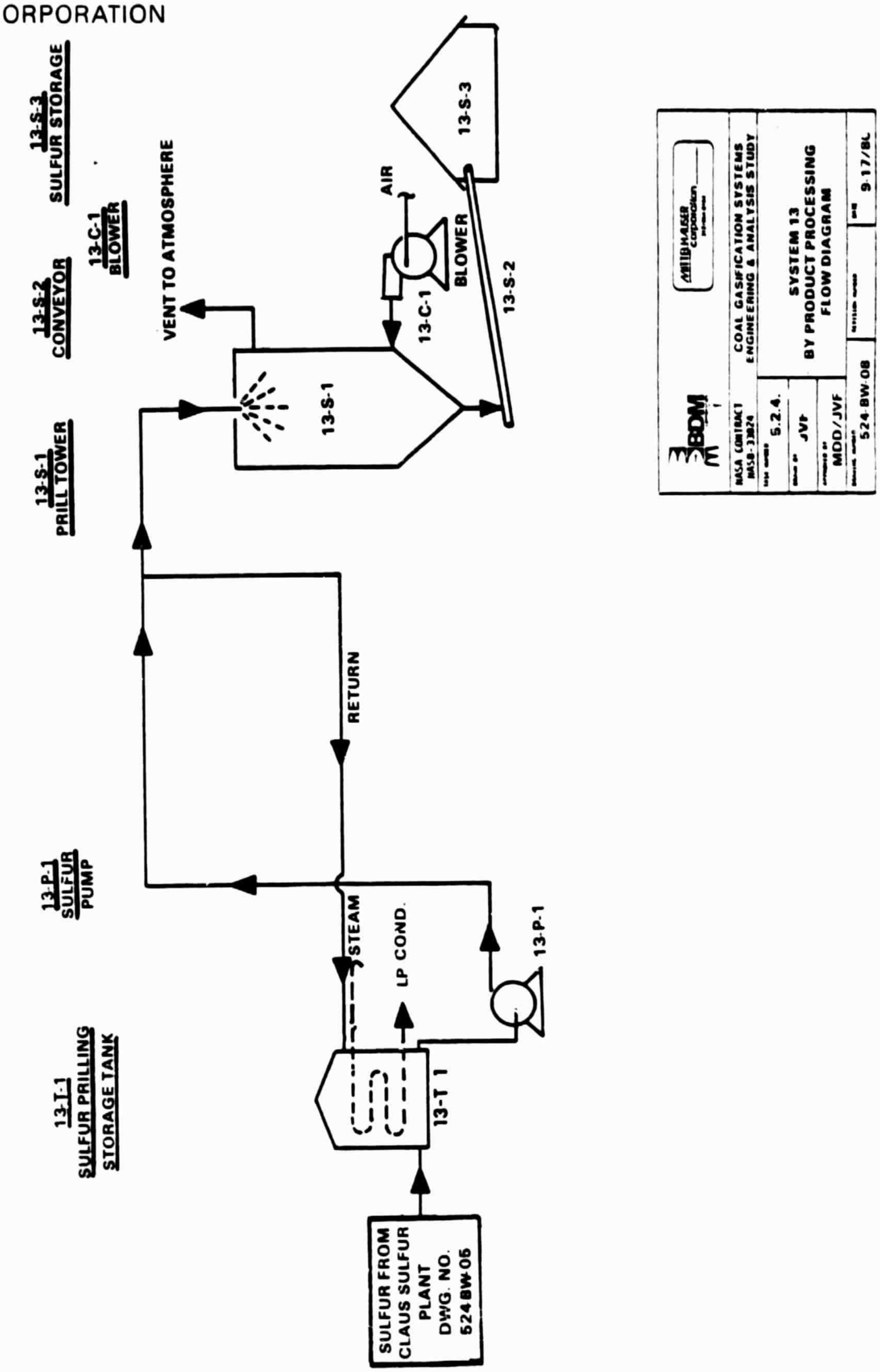

4-V-1 KNOCK OUT DRUM
4-T-2 REGENERATOR
4-E-1 SOLVENT CHILLER
4-E-2 SOLVENT COOLER
4-E-3 REGENERATOR FEED HEATER
4-E-4 ACID GAS COOLER
4-ME-1 GAS DRYING
4-P-3 MAKEUP PUMP
4-HT-1 LET DOWN TURBINE
4-C-1 RECYCLE VAPOR COMPRESSOR
4-V-2 FLASH DRUM
4-P-1 SOLVENT PUMP
4-E-5 REGENERATOR REBOILER
4-P-2 REFLUX PUMP
4-TK-1 SOLVENT STORAGE
TEG PACKAGE 4-ME-1
PRODUCT GAS
ACID GAS TO SYSTEM 5 SULFUR RECOVERY DWG. NO. 524-BW-05
GAS FROM SYSTEM 7 DWG NO 524 BW 07
4-V-1
4-T-1
4-E-1
4-E-2
4-E-3
CHILLED WATER
COOLING WATER
4-C-1
4-V-2
4-HT-1
4-E-4
4-V-3
DEMINERALIZED WATER
4-P-2
4-T-2
COND.
4-E-5
4-TK-1
4-P-3
4-P-1
CONDENSATE
BDM
MITTELHAUSER corporation
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
5.2.4.
JVF
MDD/JVF
SYSTEM 4 - SELEXOL ACID GAS REMOVAL FLOW DIAGRAM
524-BW-04
9/17/80

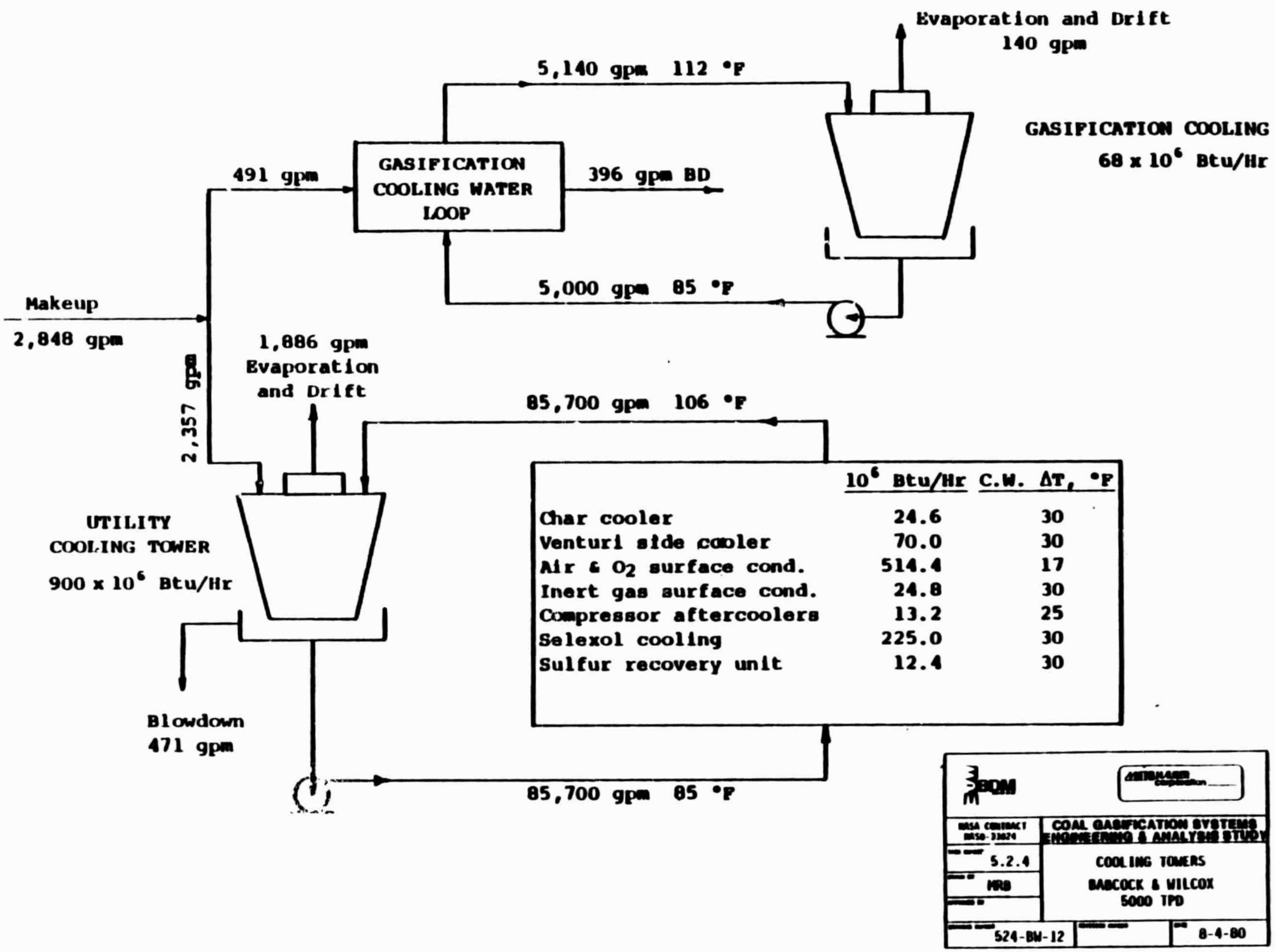

5-F-1 AIR BLOWER
5-R-1 REACTION FURNACE
5-R-2 CONVERTER
5-R-3 CONVERTER
5-R-4 CONVERTER
5-R-6 COMBUSTER
5-E-5 GAS COOLER
5-P-2 SOUR WATER PUMP
5-T-2 ABSORBER
5-ME-1 FILTER
5-S-2 SULFUR MELTER-SEPARATOR
5-V-1 KNOCK OUT DRUM
5-E-1 CONDENSER
5-E-2 CONDENSER
5-E-3 CONDENSER
5-E-4 CONDENSER
5-R-5 HYDROTREATER REACTOR
5-T-1 CONTACT COOLER
5-E-6 RECYCLE COOLER
5-P-5 SLURRY PUMP
5-P-3 CIRCULATION PUMP
5-P-4 SULFUR PUMP
5-P-1 SULFUR TRANSFER PUMP
5-S-1 AIR MIXER
STEAM
BFW
FUEL GAS
AIR
CLEAN TAIL GAS TO VENT
REDOX SOLUTION
CW
TO SOUR WATER
CONDENSATE
SULFUR PRODUCT
ACID GAS FEED FROM ACID GAS REMOVAL DWG. NO. 524-BW-04
SULFUR PIT
SULFUR TO BYPRODUCT PROCESSING DWG. NO. 524-BW-08
CLAUS UNIT
BEAVON UNIT
STRETFORD UNIT
BDM
MITTELHAUSER corporation
NASA CONTRACT NAS8-33824
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
5.2.4.
JVF
MDD/JVF
SYSTEM 6
SULFUR RECOVERY
524-BW-06
7-31-80


6-M-1 STARTUP MOTOR DRIVE FOR C-1
6-C-1 AIR COMP. AXIAL
6-ST-1 STEAM TURBINE 17,855HP CONDENSING (C-1 DRIVER)
6-EA-1 AIR COOLER
6-V-1 K.O. DRUM
6-M-2 STARTUP MOTOR DRIVE FOR C-2
6-C-2 AIR COMP. CENTRIFUGAL
6-EA-2 AIR COOLER
6-V-2 K.O. DRUM
6-E-1 SURFACE CONDENSER
6-E-4 TRIM COOLER
6-EA-3 AIR COOLER
6-C-3 O2 COMPRESSOR CENTRIFUGAL
6-ST-2 STEAM TURBINE CONDENSING 8490 (C-2 DRIVER)
6-E-2 SURFACE CONDENSER
6-ST-3 BACK PRESSURE TURBINE 9610 HP
6-M-3 STARTUP MOTOR DRIVE FOR C-3
6-E-3 TRIM COOLER
FILTERED AIR
FROM STEAM SUPER HEATER
550 PSIG 1000°F
43 PSIG 335°F
CWS
CWR
COND
550 PSIG 980°F
100 PSIA 100°F
PACKAGE AIR SEP. UNIT 6-ME-1
VENT
TRANSPORT NITROGEN
2 PSIG
HP STEAM
PACKAGE UNIT NOTE 1
OXIDANT TO GASIFIER
NOTE 1: COMPRESSOR 6-C-3 IS A PACKAGED 4-STAGE UNIT COMPLETE WITH INTERSTAGE COOLING AND K.O. DRUMS
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYTIC STUDY
BABCOCK & WILCOX
SYSTEM 6 - AIR SEPARATION
TASK 8.2.4
SEP 17, 1980

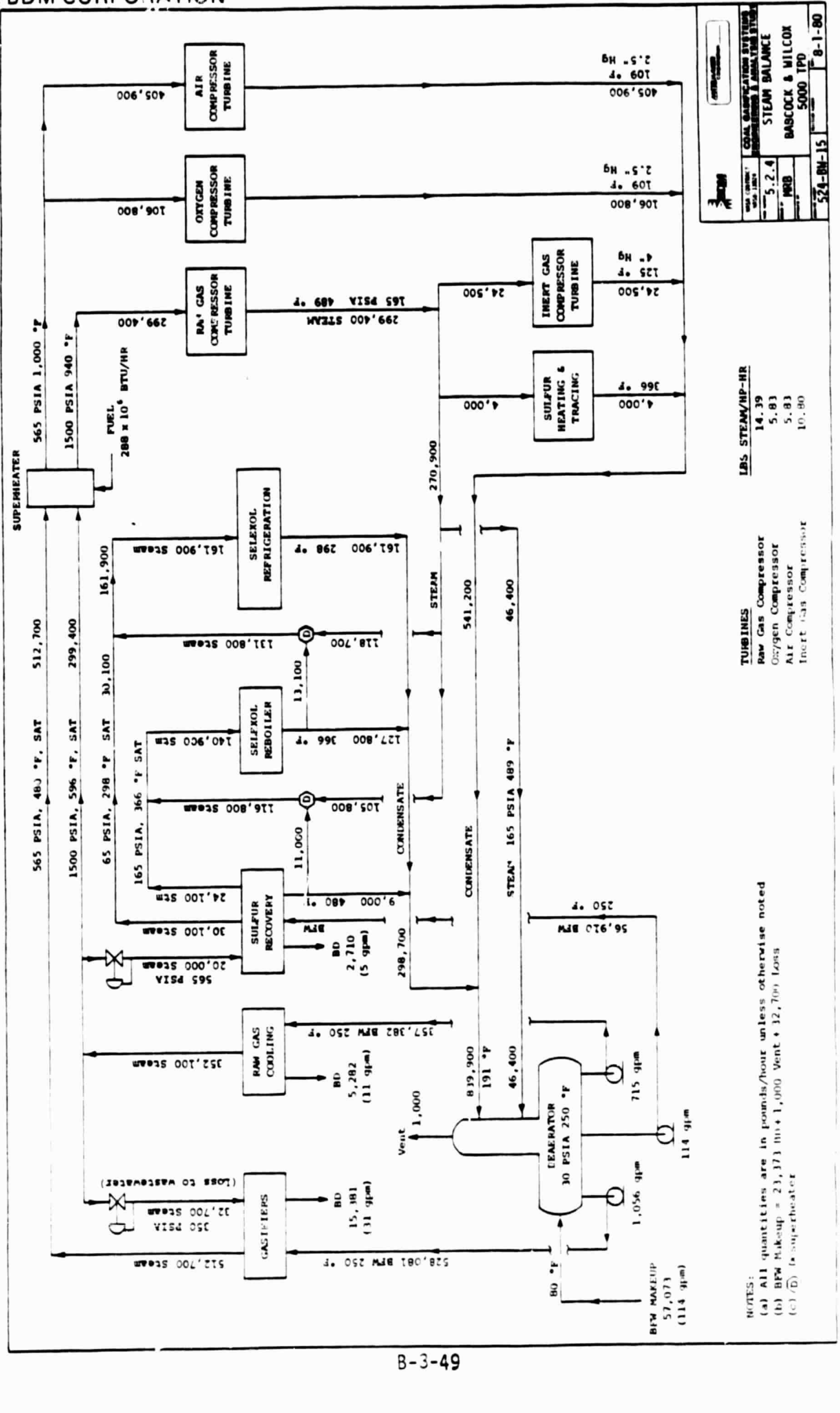


7-M-1
STARTUP MOTOR DRIVE FOR 7-C-1
7-C-1
PRODUCT GAS COMPRESSION
7-ST-1
STEAM TURBINE BACK PRESSURE (7-C-1 DRIVER) 20800 HP
7-EA-1
AIR COOLER
7-E-1
TRIM COOLER
7-V-1
K.O. DRUM
RAW GAS FROM VENTURI SCRUBBER
100°F 240 PSIA
3-1
7-C-1
7-M-1
360°F 668 PSIA
7-ST-1
920°F
HP STEAM FROM SUPERHEATER
150 PSIG 480°F
IP STEAM TO DISTRIBUTION
7-EA-1
7-E-1
CWS
CWR
7-V-1
100°F
TO ACID GAS REMOVAL
NASA CONTRACT NAS8-33824
TASK 5.2.4
KJK
JVF
524-BW-07
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
BABCOCK & WILCOX
SYSTEM 7
PRODUCT GAS COMPRESSION
SEP 17, 1980

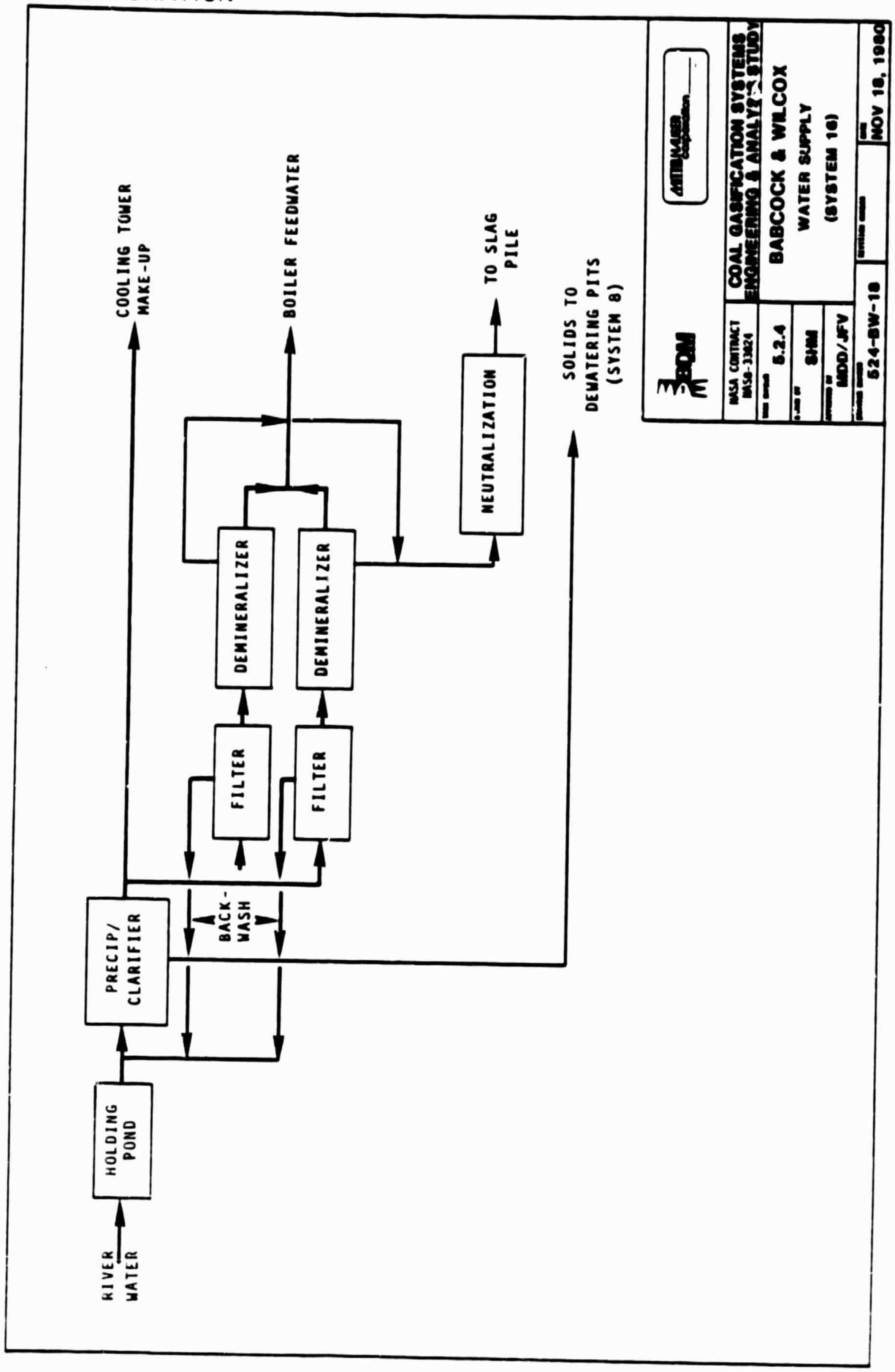

13-S-3
SULFUR STORAGE
13-C-1
BLOWER
13-S-2
CONVEYOR
13-S-1
PRILL TOWER
13-P-1
SULFUR
PUMP
13-T-1
SULFUR PRILLING
STORAGE TANK
VENT TO ATMOSPHERE
AIR
BLOWER
13-C-1
13-S-1
13-S-2
13-S-3
RETURN
STEAM
LP COND.
13-P-1
13-T 1
SULFUR FROM
CLAUS SULFUR
PLANT
DWG. NO.
524 BW-06
NASA CONTRACT
NAS8-33824
5.2.4.
JVF
MDD/JVF
524-BW-08
COAL GASIFICATION SYSTEMS
ENGINEERING & ANALYSIS STUDY
SYSTEM 13
BY PRODUCT PROCESSING
FLOW DIAGRAM

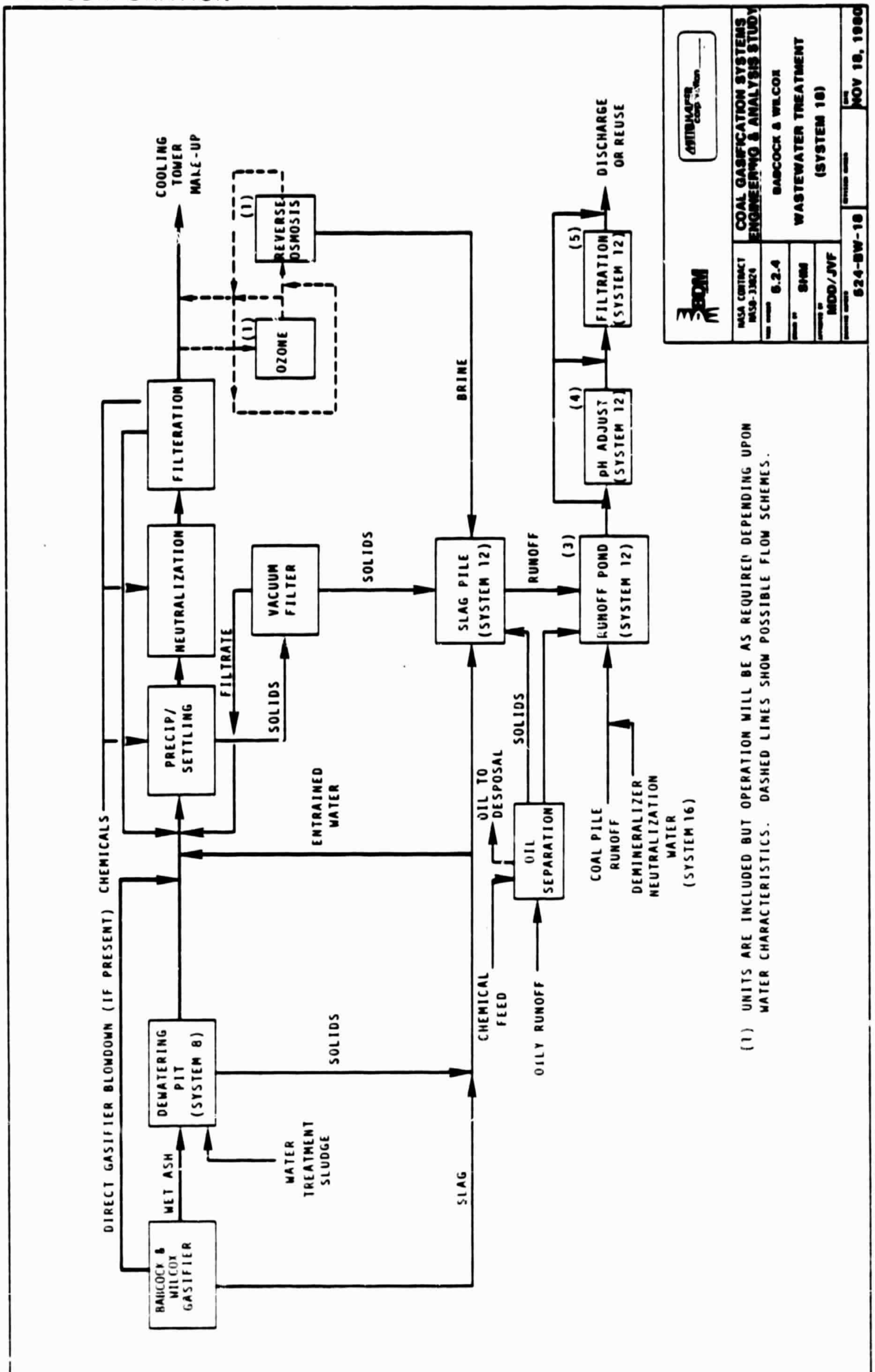


	10^6 Btu/Hr	C.W. ΔT, °F
Char cooler	24.6	30
Venturi side cooler	70.0	30
Air & O_2 surface cond.	514.4	17
Inert gas surface cond.	24.8	30
Compressor aftercoolers	13.2	25
Selexol cooling	225.0	30
Sulfur recovery unit	12.4	30



STEAM BALANCE
BABCOCK & WILCOX
5000 TPD
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
5.2.4
MRB
524-BW-15
8-1-80
AIR COMPRESSOR TURBINE
OXYGEN COMPRESSOR TURBINE
RAW GAS COMPRESSOR TURBINE
INERT GAS COMPRESSOR TURBINE
SULFUR HEATING & TRACING
SUPERHEATER
FUEL 288 x 10^6 BTU/HR
565 PSIA 1,000 °F
1500 PSIA 940 °F
405,900
106,800
299,400
299,400 STEAM
165 PSIA 489 °F
24,500
4,000
109 °F
2.5" Hg
125 °F
4" Hg
366 °F
270,900
SELEXOL REFRIGERATION
161,900 steam
161,900
298 °F
131,800 steam
118,700
13,100
SELEXOL REBOILER
140,900 stm
127,800
366 °F
116,800 steam
105,800
11,060
SULFUR RECOVERY
24,100 stm
9,000
480 °F
30,100 steam
20,000 steam
565 PSIA
BFW
BD 2,710 (5 gpm)
298,700
RAW GAS COOLING
352,100 steam
157,382 BFW 250 °F
BD 5,282 (11 gpm)
GASIFIERS
32,700 steam
350 PSIA
(Loss to wastewater)
512,700 steam
528,081 BFW 250 °F
BD 15,381 (31 gpm)
565 PSIA, 480 °F, SAT 512,700
1500 PSIA, 596 °F, SAT 299,400
65 PSIA, 298 °F SAT 30,100
165 PSIA, 366 °F SAT
CONDENSATE
STEAM
541,200
46,400
STEAM 165 PSIA 489 °F
56,920 BFW
250 °F
819,900
191 °F
DEAERATOR 30 PSIA 250 °F
Vent 1,000
715 gpm
114 gpm
1,056 gpm
80 °F
BFW MAKEUP 57,073 (114 gpm)
TURBINES
Raw Gas Compressor
Oxygen Compressor
Air Compressor
Inert Gas Compressor
LBS STEAM/HP-HR
14.39
5.83
5.83
10.80
NOTES:
(a) All quantities are in pounds/hour unless otherwise noted
(b) BFW Makeup = 23,373 lb + 1,000 Vent + 12,700 Loss
(c) (D) is superheater


RIVER WATER
HOLDING POND
PRECIP/ CLARIFIER
BACK-WASH
FILTER
FILTER
DEMINERALIZER
DEMINERALIZER
NEUTRALIZATION
COOLING TOWER MAKE-UP
BOILER FEEDWATER
TO SLAG PILE
SOLIDS TO DEWATERING PITS (SYSTEM 8)
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
BABCOCK & WILCOX
WATER SUPPLY
(SYSTEM 16)
NASA CONTRACT NAS8-33824
5.2.4
SHM
MDD/JFV
524-BW-16
NOV 18, 1980


BABCOCK & WILCOX GASIFIER
WET ASH
DIRECT GASIFIER BLOWDOWN (IF PRESENT)
CHEMICALS
DEWATERING PIT (SYSTEM 8)
WATER TREATMENT SLUDGE
SOLIDS
SLAG
PRECIP/ SETTLING
NEUTRALIZATION
FILTERATION
FILTRATE
SOLIDS
VACUUM FILTER
SOLIDS
ENTRAINED WATER
OZONE
(1)
REVERSE OSMOSIS
(1)
COOLING TOWER MAKE-UP
BRINE
SLAG PILE (SYSTEM 12)
RUNOFF
CHEMICAL FEED
OIL TO DESPOSAL
OIL SEPARATION
OILY RUNOFF
SOLIDS
(3)
RUNOFF POND (SYSTEM 12)
COAL PILE RUNOFF
DEMINERALIZER NEUTRALIZATION WATER (SYSTEM 16)
(4)
pH ADJUST (SYSTEM 12)
(5)
FILTRATION (SYSTEM 12)
DISCHARGE OR REUSE
(1) UNITS ARE INCLUDED BUT OPERATION WILL BE AS REQUIRED DEPENDING UPON WATER CHARACTERISTICS. DASHED LINES SHOW POSSIBLE FLOW SCHEMES.
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
BABCOCK & WILCOX
WASTEWATER TREATMENT
(SYSTEM 18)
NASA CONTRACT NAS8-33824
5.2.4
SHM
MDD/JVF
524-BW-18
NOV 18, 1980

EQUIPMENT LIST
TVA MBG MODULE
B&W GASIFIER
SYSTEM NO: 1 - COAL PREPARATION & FEEDING

ITEM NUMBER	SERVICE	QUANTITY SPARE	QUANTITY OPERATION	DESCRIPTION
11-S-1	COAL STORAGE			COAL SILO
11-S-2	TRAMP IRON REMOVAL		3	MAGNETIC
1-CV-1	COAL TRANSPORT TO SYSTEM 1		3	COVERED CONVEYOR
1-BN-1	FEED SURGE	1	2	700 TON COAL BIN
1-CV-2	CONTROL FEED RATE	1	2	WEIGHT BELT CONVEYOR
1-ME-1	CRUSH COAL TO 1/4" x0	1	2	CAGE MILL
1-ME-2	SEPARATE COAL AT 1/4"	1	2	VIBRATING SCREEN
1-S-3	SAMPLE COAL	1	2	
1-ME-3	FINE GRIND COAL	1	2	PULVERIZER

THE BDM CORPORATION

EQUIPMENT LIST
TVA MBG MODULE
B&W GASIFIER
SYSTEM NO: 1 - COAL PREPARATION & FEEDING

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
1-F-1	AIR HEAT DRYING	1	2	FIRED HEATER
1-P-1	TRANSPORT AIR SUPPLY	1	2	AIR BLOWER
1-S-1	RECOVER PULVERIZE COAL			CYCLONES
1-S-2A,B	DUST CONTROL	1	2	BAG HOUSE
1-V-1	FEED SURGE	1	2	P. C. RESERVOIR TANK
1-V-2	PRESSURIZE COAL	1	2	PRESSURIZED LOCK HOPPER
1-V-3	FEED CONTINUITY	1	2	FEED TANK
1-V-4	PRESSURIZED INERT GAS	1	2	PRESSURIZED TANK

EQUIPMENT LIST
TVA MBG MODULE
B&W GASIFIER
SYSTEM NO: 2 - COAL GASIFICATION

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
2-P-1	B.F.W MAKEUP PUMP	2	4	CENTRIFUGAL PUMP
2-P-2	BOILER FEED WATER PUMP	2	4	CENTRIFUGAL PUMP
2-V-1	HEAT RECOVERY SERVICE	1	2	STEAM DRUM
2-V-2	SLAG DISCHARGE	1	2	SLUICE TANK
2-V-3	SLAG DISCHARGE	1	2	SLAG LOCK HOPPER
2-R-1	GASIFICATION	1	2	B&W GASIFICATION REACTOR
				C-3

EQUIPMENT LIST
TVA MBG MODULE
B&W GASIFIER
SYSTEM NO: 3 - INITIAL GAS CLEANUP & COOLING

ITEM NUMBER	SERVICE	QUANTITY SPARE	QUANTITY OPERATION	DESCRIPTION
3-P-1	GAS DEHUMIDIFICATION	2	4	BOILER FEED WATER CENTRIFUGAL PUMP
3-P-2	GAS DEHUMIDIFICATION	2	4	BOILER FW MAKEUP CENTRIFUGAL PUMP
3-P-3	FINAL GAS DEHUMIDIFICATION	2	4	CENTRIFICAL WATER RECYCLE PUMP
3-P-4	GAS DEHUMIDIFICATION	2	4	MID TOWER CENTRIFUGAL CIRCULATION PUMP
3-V-1	HP STEAM PRODUCTION	1	2	STEAM DRUM
3-V-2	GAS DEHUMIDIFICATION	1	2	PACKED COLUMN GAS COOLER
3-ME-1	GAS COOLING	1	2	WASTE HEAT BOILER
3-E-1	GAS DEHUMIDIFICATION	2	4	CIRCULATION STREAM COOLER HEAT EXCHANGER
3-S-1	GAS CLEANUP			PRIMARY CYCLONE

EQUIPMENT LIST
TVA MBG MODULE
B&W GASIFIER
SYSTEM NO: 3 - INITIAL GAS CLEANUP & COOLING

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
3-S-2	GAS CLEANUP			SECONDARY CYCLONE
3-S-3	GAS CLEANUP	1	2	VENTURI SCRUBBER

EQUIPMENT LIST
TVA MBG MODULE
B&W GASIFIER
SYSTEM NO: 4 - ACID GAS REMOVAL

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
4-V-1	SOLVENT KNOCK-OUT DRUM	0	1	
4-V-2	SOLVENT FLASH DRUM	0	1	
4-V-3	REGENERATOR KNOCK-OUT	0	1	
4-T-1	ACID GAS ABSORBER	0	1	
4-T-2	SOLVENT REGENERATOR	0	1	
4-E-1	SOLVENT CHILLER	0	1	SHELL & TUBE EXCHANGER
4-E-2	SOLVENT COOLER	0	1	SHELL & TUBE EXCHANGER
4-E-3	REGENERATOR FEED PRE-HEAT EXCHANGER	0	1	SHELL & TUBE EXCHANGER
4-E-4	ACID GAS COOLER	0	1	AIR FAN EXCHANGER

EQUIPMENT LIST
TVA MBG MODULE
B&W GASIFIER
SYSTEM NO: 4 - ACID GAS REMOVAL

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
4-E-5	REGENERATOR REBOILER	0	1	SHELL & TUBE EXCHANGER
4-P-1	SOLVENT CIRCULATION PUMP	1	1	
4-P-2	REGENERATOR REFLEX PUMP	1	1	
4-P-3	SOLVENT TRANSFER PUMP	1	1	
4-TK-1	SOLVENT STORAGE TANK	0	1	
4-ME-1	TEG GAS DRYING PACKAGE	0	1	INCLUDES TEG CIRCULATION PUMP, TEG CONTRACTOR AND TEG REGENERATOR
4-C-1	RECYCLE VAPOR COM- PRESSOR	0	1	
4-HT-1	RICH SOLVENT LET DOWN TURBINE	0	1	

EQUIPMENT LIST
TVA MBG MODULE
B&W GASIFIER
SYSTEM NO: 5 - SULFUR RECOVER & TAIL GAS CLEAN-UP

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
5-P-1	SULFUR PRODUCT PUMP	1	1	
5-P-2	STRETFORD SOUR WATER PUMP	1	1	
5-P-3	REDOX SOLUTION CIRCULATION PUMP	1	1	
5-P-4	STRETFORD SULFUR TRANSFER PUMP	1	1	
5-P-5	REACTION FURNACE AIR BLOWER	1	1	
5-S-1	AIR OXIDATION MIX TANK	0	1	
5-S-2	STRETFORD SULFUR SEPARATOR MELTOR	0	1	
5-S-3	MOLTER SULFUR STORAGE PIT	0	1	
5-V-1	ACID GAS KNOCK-OUT DRUM	0	1	

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EQUIPMENT LIST
TVA MBG MODULE
B&W GASIFIER
SYSTEM NO: 5 - SULFUR RECOVER & TAIL GAS CLEAN-UP

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
5-R-1	REACTION FURNACE	0	1	ACID GAS BURNER AND STEAM GENERATION
5-R-2,3,4	SULFUR CONVERTERS	0	2	HORIZONTAL REACTORS
5-R-5	BEAVON REACTORS	0	1	HORIZONTAL GAS HYDROLYSIS REACTOR
5-T-1	BEAVON UNIT CONDENSOR	0	1	
5-T-2	STRETFORD ABSORBER	0	1	
5-E-1,2,3,4	SULFUR CONDENSORS	0	4	SHELL & TUBE EXCHANGER
5-E-5	BEAVON UNIT GAS COOLER	0	1	SHELL & TUBE EXCHANGER
5-E-6	STRETFORD RECYCLE COOLER	0	1	

EQUIPMENT LIST
TVA MBG MODULE
B&W GASIFIER
SYSTEM NO: 6 - AIR SEPARATION

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
6-C-1	AIR COMPRESSION	0	2	AXIAL COMPRESSOR
6-C-2	SECOND AIR COMPRESSOR	0	2	CENTRIFUGAL COMPRESSOR
6-C-3	OXYGEN COMPRESSOR	0	2	CENTRIFUGAL COMPRESSOR
6-M-1	START UP MOTOR FOR 6-C-1		2	
6-M-2	START UP MOTOR FOR 6-C-2		2	
6-M-3	START UP MOTOR FOR 6-C-3		2	
6-ST-1	STEAM TURBINE DRIVE FOR 6-C-1		2	
6-ST-2	STEAM TURBINE DRIVE FOR 6-C-2		2	
6-ST-3	STEAM TURBINE DRIVE FOR 6-C-3		2	

EQUIPMENT LIST
TVA MBG MODULE
B&W GASIFIER
SYSTEM NO: 6 - AIR SEPARATION

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
6-V-1	FIRST AIR K.O. DRUM		2	
6-V-2	SECOND AIR K.O. DRUM		2	
6-V-3	OXYGEN K.O. DRUM		2	
6-EA-1	FIRST AIR COOLER		2	AIR FIN
6-EA-2	SECOND AIR COOLER		2	AIR FIN
6-EA-3	OXYGEN COOLER		2	AIR FIN
6-E-1	TURBINE EXHAUST CONDENSOR		2	SURFACE CONDENSOR
6-E-2	TURBINE EXHAUST CONDENSOR		2	SURFACE CONDENSOR
6-E-3	AIR TRIM COOLER		2	COOLING WATER EXCHANGER

THE BDM CORPORATION

EQUIPMENT LIST
TVA MBG MODULE
B&W GASIFIER
SYSTEM NO: 6 - AIR SEPARATION

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
6-E-4	AIR TRIM COOLER		2	COOLING WATER EXCHANGER

THE BDM CORPORATION

EQUIPMENT LIST
TVA MBG MODULE
B&W GASIFIER
SYSTEM NO: 7 - GAS COMPRESSION

ITEM NUMBER	SERVICE	QUANTITY		DESCRIPTION
		SPARE	OPERATION	
7-C-1	PRODUCT GAS COMPRESSION	0	1	CENTRIFUGAL COMPRESSOR
7-M-1	START UP MOTOR FOR 7-C-1	0	1	
7-ST-1	BACKPRESSURE TURBINE DRIVE FOR 7-C-1	0	1	
7-EA-1	COMPRESSOR DISCHARGE COOLER	0		AIR FIN
7-E-1	PRODUCT GAS TRIM COOLING	0	1	COOLING WATER EXCHANGER
7-V-1	COMPRESSED GAS CONDENSATE REMOVA	0	1	K.O. DRUM

EQUIPMENT LIST
TVA MBG MODULE
B&W GASIFIER
SYSTEM NO: 13 - BY PRODUCT PROCESSING

ITEM NUMBER	SERVICE	QUANTITY SPARE	QUANTITY OPERATION	DESCRIPTION
13-T-1	MOLTEN SULFUR STORAGE STORAGE TANK	0	2	STEAM HEATED 500 TONS EACH
13-P-1	PRILL TOWER FEED PUMP	1	1	MOLTEN SULFUR PUMP
13-S-1	PRILLING TOWER	0	1	
13-S-2	PRILLED SULFUR CON-VEYOR	0	1	
13-C-1	AIR BOILER	1	1	
13-S-3	PRILLED SULFUR STORAGE	0	1	5000 TONS STORAGE BUILDING

APPENDIX B-4

LURGI AND BGC/LURGI COAL GASIFICATION PLANTS

DEFINITION LEVEL DESIGNS

TABLE OF CONTENTS

LIST OF TABLES

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LIST OF DRAWINGS

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1.0 INTRODUCTION

The United States, after a number of years of development based on plentiful and inexpensive oil and natural gas, is entering a period of time when it is essential to supplement these energy sources by the use of coal. Coal is the nation's most plentiful fossil fuel. Coal gasification is a means of accomplishing this. While utilization of coal through conversion to gaseous products is not new, there is no industry within the US which might serve as a base for establishing cost, operational reliability and requirements, and design data for the large scale environmentally acceptable plants needed.

The Tennessee Valley Authority with systems engineering and analysis support from the George C. Marshall Space Flight Center has initiated a project which would establish the commercial base and demonstrate the requirements for gasifying coal in a large integrated facility. The project consists of gasifying 20,000 tons per day of Eastern coal in a four module plant, the construction of which is staggered to accommodate efficient use of construction manpower and product market development.

The purpose of this study is the systematic engineering and cost analysis of five selected gasifier technologies and the other associated systems required to produce medium Btu gas for delivery into a 600 psig distribution system in Northern Alabama. This effort in a series of design studies provides a reference basis for selection of the final plant configuration and choice of technologies.

The methodology consists of selection of a systematic breakdown of the facility for purpose of study, identification of available technologies for each system, development of a definition level design and cost analysis, conducting series of trade studies using the definition design as a basis, and finally development of reference facility designs and cost analyses based on the previous work. This report covers the definition design efforts for two of the five designs--the Lurgi and BGC/Lurgi gasification systems. The designs for the other gasification systems--the Koppers-Totzek, the Texaco and the Babcock and Wilcox--appear in Appendices B-1, B-2 and B-3, respectively.

The trade studies were done primarily based on the Texaco and K-T cases and previous to this work with the other three gasifiers. Therefore, the designs for the Lurgi and BGC/Lurgi that are presented here, though they are of the first level effort, have the results of the trade studies built in.

This report contains a description of the plant configuration chosen, a description of the technology chosen for each system, the material and energy balances. The cost analysis for the Lurgi and BGC/Lurgi is presented in Appendix D.

2.0 SUMMARY

Definition level plant designs have been prepared based on Lurgi and BGC/Lurgi coal gasification processes. Each of these plants process 20,000 TPD total raw coal to the gasifiers.

The Lurgi coal gasification process consists of reacting one inch by twenty-eight mesh coal with oxygen and steam in a fixed bed reactor to produce medium BTU gas. Coal is fed into the top of the reactor from where it moves downward by gravity countercurrent to the oxygen steam and gasification products. Ash and unreacted carbon are removed from the bottom by a mechanical grate which is kept relatively cool by the flow of steam and oxygen into the bottom of the reactor. A portion of the steam requirement is generated in the reactor jacket. Products, partially cooled by contact with coal feed are further cooled by a quench and waste heat boiler. Heavy products, ammonia and some H_2S are recovered from the quench liquor in the waste water treating section.

The BGC/Lurgi is similar to the Lurgi in description except that ash is removed from the bottom of the reactor as molten slag. Molten slag is removed from the reactor by quenching in a water bath to form ash granules which are removed as a slurry. Since there is no grate cooling requirement the steam requirement is much less than that of the Lurgi. The result is that lower quantities of vapor state materials per unit of coal allow increased coal throughout per unit reactor cross section, higher maximum temperatures with less methane production, and less hydrogen production.

Coal fines produced in the feed handling preparation steps of the Lurgi and BGC/Lurgi designs are either burned as boiler fuel or exported as plant byproducts. The plants are each designed to be built in four distinct stand alone modules processing 5000 TPD each. Exceptions are such facility wide sections as coal handling and general facilities. Module construction is staggered to allow efficient use of construction manpower and the development of product markets. Tars, oils and phenolic compounds are burned as boiler fuel along with coal fines to produce steam requirements for the process units. No additional steam for prime mover power is generated. Purchased electricity is utilized to fill all power requirements not covered by process generated steam. Because of the decision to burn tars, oils and phenolic compounds the plants products are medium BTU gas, sulfur, and ammonia in the Lurgi and BGC/Lurgi cases. All plant solids are disposed of on site. The plants are designed for recycle of treated waste water with zero plant effluent.

Tables 2.1 and 2.2 give a summary of the process and cost results obtained in this study.

TABLE 2.1
FACILITY PROCESS RESULT SUMMARY*

ITEM	LURGI	BGC/LURGI
COAL, T/YR	10,000,000	10,000,000
FINES SOLD, T/YR		3,918,000
ELECTRICITY, 1000 Kwh/YR		
YIELD MMSCFD	1,160	960
HHV BTU/SCF	308	384
COMPOSITION lb/hr		
Hydrogen	29,968	15,183
Nitrogen	3,928	3,889
Carbon Monoxide	152,127	438,365
Carbon Dioxide	363,892	20,591
Methane	45,720	36,664
Ethane	2,371	1,901
Light HC	3,892	2,998
Hydrogen Sulfide	61	70
Carbonyl Sulfide	300	192
Water	84	70
Total	602,343	519,923
SULFUR 1000 TONS/YR	58	59
AMMONIA 1000 TONS/YR	89	89
EFFICIENCY - PERCENT**	68.0	76.4

* PER YEAR EXCEPT WHERE NOTED

** EFFICIENCY BASED ON COAL CONSUMED, PURCHASED ELECTRICITY AS ELECTRICITY AND MBG PRODUCT.

TABLE 2.2
FACILITY COST SUMMARY

ITEM	LURGI	BGC/LURGI
CAPITAL REQUIREMENTS (1980 DOLLARS)	2,747,000	2,061,000
ANNUAL OPERATING COSTS		
COAL @ 1.25/MMBTU	$274 MM	$274 MM
OTHER	93	35
PRODUCT COSTS (CONSTANT 1980 DOLLARS PER MMBTU)	5.26	4.06

3.0 GENERAL FACILITY DESCRIPTION

The TVA coal gasification facility is to be designed to process 20,000 TPD of Kentucky Number 9 coal into medium BTU gas having not more than 200 ppmv sulfur. The coal specifications are given in Table 3.1. Design specifications were given in a TVA document, "Design Criteria for Conceptual Designs and Assessments of TVA's Coal Gasification Demonstration Plant", March 1980, provided by NASA. In order that the most efficient use of construction labor might be accomplished and in order to allow time for development of a user network for the MBG product and provide for maximum operating flexability the plant is to be constructed in four 5000 TPD modules.

The plant has been divided into a group of interrelated systems according to the guidelines given in Table 3.2 for purposes of systematically studying the available processes for inclusion in the plant design. A summary of the processes available for each system has been published earlier in "Coal Gasification Catalog" as a part of Task 5.1 of this study. For each of the five gasification technologies to be considered for the plant a combination of systems was selected to provide a definition level design. The purpose of definition level designs is to provide the starting point for a series of engineering analyses and trade studies which result in a more definitive and optimin plant configuration and process selection in the next level of design. The two designs presented in this report, while catagorized as definition level designs, have the benefit of earlier trade studies performed based on definition level Texaco and Koppers-Totzek designs. Therefore they represent an advanced version of definition level design.

3.1 Methodology of Design

The selection of systems defined for the plant have been arranged for each of the two gasification processes as shown in the block flow diagrams in Sections 4.0 and 5.0. For each system an analysis of available processes and technologies was accomplished based on:

- A system - level approach
  - select applicable system design from design data base
  - data availability and relevance
  - adjustments for current application
- No secrecy agreements required
- Production of system - level block flow diagrams plus documentation of I/O, interfaces, costs and other requirements as the basis for trades and second level reference facility designs.

For each process selected available published designs were studied. Those designs most nearly meeting the requirements of this effort were chosen as a basis for defining the requirements of the definition level design. These designs were scaled and adjusted as required to meet the

TABLE 3.1
COAL CHARACTERISTICS

	Mean[1]	Standard Deviation[2]
H.H.V., as Received, Btu/lb	10.980	547.6
Total Moisture, wt %	9.564	1.878
Inherent Moisture, wt %	3.25	0.75
Bulk Density, as Received, lb/ft[3]	45.	-
Free Swelling Index[3]	(3.0-6.5)	-
Grindability Index	59.	5.117
2.1.2 Proximate Analysis, Dry, wt %		
Volatile Matter	37.54	1.878
Fixed Carbon	46.63	1.604
Ash	15.83	3.086
TOTAL	100.00	
2.1.3 Ultimate Analysis, Dry, wt %		
Carbon	67.31	2.794
Hydrogen	4.757	.2409
Nitrogen	1.529	.001326
Oxygen	6.343	1.085
Sulfur	4.100	.4858
Ash	15.83	3.086
Chlorine	.1310	.05965
TOTAL	100.000	

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[1] Mean = $\bar{x} = \sum_{i}^{n} x_i/n$, based on analysis of 14 samples of Kentucky No. 9 coal received by TVA from various mines during the period 1972-1977; results are rounded to four significant figures.

[2] Standard Deviation = $1/(n-1)\ \{\sum_{i}^{n}(x_i-\bar{x})^2\}^{1/2}$, based on analysis of the 14 sample coals; results are rounded to four significant figures.

[3] Data indicates range of values; for design purposes, assume FSI = 6.5.

TABLE 3.2
LIST OF SYSTEMS

SYSTEM NO.	SYSTEM DESCRIPTION
1	COAL PREPARATION & FEEDING
2	GASIFICATION
3	INITIAL GAS CLEANUP & COOLING
4	ACID GAS REMOVAL
5	SULFUR RECOVERY
6	AIR SEPARATION
7	COMPRESSION
8	PROCESS SOLIDS TREATMENT
9	INCINERATOR
10	INSTRUMENTATION & CONTROL
11	COAL HANDLING
12	SOLIDS DISPOSAL
13	BYPRODUCT PROCESSING
14	PLANT POWER SYSTEM
15	STEAM GENERATION/DISTRIBUTION
16	RAW WATER MAKEUP
17	COOLING WATER SYSTEM
18	WASTE WATER TREATMENT
19	GENERAL FACILITIES

TABLE 3.3
SYSTEM TECHNOLOGY ASSESSMENT

	SYSTEM	LURGI	BGC-SLAGGER
1	COAL PREPARATION & FEEDING	CP	CP
2	GASIFICATION	CP	RD
3	INITIAL GAS CLEANUP & COOLING	CP	CP
4	ACID GAS REMOVAL	CA	CA
5	SULFUR RECOVERY & TAIL GAS TREATMENT	CA	CA
6	AIR SEPARATION	CP	CP
7	COMPRESSION	CP	CP
8	PROCESS SOLIDS TREATMENT	CP	CP
9	INCINERATOR	-	-
10	INSTRUMENTATION & CONTROL	CP	CP
11	COAL HANDLING	CP	CP
12	SOLIDS WASTE RECYCLING/DISPOSAL	CP	CP
13	BYPRODUCT PROCESSING	CP/CA	CP/CA
14	PLANT POWER SYSTEM	CP	CP
15	STEAM GENERATION/DISTRIBUTION	CP/CA	CP/CA
16	WATER SUPPLY	CP	CP
17	COOLING WATER SYSTEM	CP	CP
18	WASTE WATER TREATMENT	CA/RD	CA/RD
19	GENERAL FACILITIES	-	-

KEY: CP = COMMERCIALLY PROVEN, CA = COMMERCIALLY AVAILABLE, RD = READY FOR DEMONSTRATION

I/O and interface requirements of the present module designs. These adjusted designs have been placed in the block flow diagram sequence and used as a basis for material balances, energy balances, and cost analyses. Table 3.3 presents the status of systems chosen.

3.2 System Descriptions

Many of the systems shown in the block flow diagrams are either the same for all designs or similar in description for each of the two designs except for size and cost considerations. This section defines each of these systems. More detailed descriptions of those systems specific to Lurgi and BGC/Lurgi are given in Sections 4.0 and 5.0, respectively.

3.2.1 System 11 - Coal Handling

The Coal Handling System provides for the unloading of coal delivered to the plant either by barge or truck, reclaiming the coal from storage, reducing the size of coal, and transporting the coal to Coal Preparation and Feeding, System 1.

Raw coal is unloaded from barges by the barge unloading subsystem which is designed to unload up to ten 1500 ton capacity barges per shift. The coal is unloaded at an average rate of 1200 tons per hour on a 5 day week basis. Coal is transferred by conveyor to a radial stacker which then produces a kidney shaped coal pile containing live and dead storage. Coal is reclaimed from live storage and conveyed to a Bradford breaker where it is reduced in size to 2"x0. Coal from trucks is unloaded into a chute from which it is conveyed to the Bradford breaker. Crushed coal from the Bradford breaker is transported to day storage silos from which it is transfered via vibrating belt conveyors to coal preparation and feeding, System 1, for further processing. Coal fines from the Bradford breaker are collected and sent to the gasification unit, System 2.

3.2.2 System 1 - Coal Preparation and Feeding

The Coal Preparation and Feeding System takes primary crushed coal from the coal handling system, grinds and dries the coal to its final size requirement, and stores the prepared coal in intermediate surge bins for transfer to the coal gasification system. Since each of the three gasifiers has different feed requirements this system is further described in the appropriate section.

3.2.3 System 2 - Coal Gasification

This system takes the prepared coal from System 2 and converts it into gaseous products and slag byproduct. The specific gasifier descriptions are given in the appropriate section.

3.2.4 System 3 - Initial Gas Cooling and Cleanup

This system takes hot gases from System 2 and reduces the temperature as appropriate for downstream processing, by quenching, steam generation and hear exchange. Products are sent to compression and condensate treating. Each design has different requirements which are described in the appropriate section.

3.2.5 System 7 - Compression

This system receives raw gas from the gas cooling section and compresses it prior to acid gas removal sufficient to meet a 600 psig final plant discharge pressure. Since each gasifier has a different discharge pressure and gas composition this system is further described in the appropriate later section.

3.2.6 System 4 - Acid Gas Removal

The purpose of this system is to receive raw gas and remove sufficient acid gas to meet the plant product specifications of 200 ppmv sulfur and 285 BTU/SCF HHV.

Though the material and energy balances and total system cost for this system vary between the two designs presented here the system descriptions are otherwise identical

The Selexol Sulfur Removal Unit is a proprietary process licensed by Allied Chemical Co. The primary purpose of this system is to remove H_2S and COS from the product gas stream in order to obtain a sulfur concentration of not more than 200 ppmv. Secondarily, the process removes CO_2, which increases the gas heating value.

The Selexol process removes sulfur compounds and carbon dioxide by means of countercurrent contact in an absorber. The physical absorption of the compounds to be removed is done using the dimethyl ether of polyethylene glycol as a solvent. Chilled solvent is used. Solvent chilling is accomplished by means of an absorption refrigeration system utilizing low pressure gasifier jacket steam.

CO_2 removal from the rich solvent leaving the absorber is accomplished by a series of successively lower pressure flashes. Flashed gas is recycled to the absorber inlet. Sulfur compounds are removed in the stripping column. The stripping column utilizes a steam heated reboiler. The stripper overheat gas, after cooling to about 120°F, flows to the Sulfur Recovery and Tail Gas Treatment Unit - System 5.

The sour gas from the Selexol unit is rich in CO_2, and at slightly above atmospheric pressure.

3.2.7 System 5 - Sulfur Recovery and Tail Gas Treatment

The Sulfur Recovery and Tail Gas Treatment system receives H_2S and some COS and CO_2 from System 4 and converts the sulfur bearing gases into molten sulfur. The system is similar in both designs.

Acid gas from Acid Gas Removal, System 4, is fed to a Claus-type three-stage sulfur recovery unit utilizing a proprietary process for handling lean H_2S acid gases. Typically in a Claus type sulfur plant, the acid gas is first passed through a knockout drum before entering the reaction furnace. The chemistry of the process involves converting the H_2S to elemental sulfur according to the following equation;

$$2H_2S + SO_2 \longrightarrow 3S + 2H_2O$$

Any hydrocarbons in the acid gas are burned to CO_2 and H_2O.

The reactions are exothermic, and the heat liberated generates steam in the reaction furnace boiler and in the sulfur condenser. The sulfur from each condenser is drained to a recovery pit in Byproduct Processing, System 13, and the tail gas from the final condenser is fed to a Beavon tail gas treating unit where essentially complete removal of the remaining sulfur compounds is achieved before discharge to the atmosphere. The Beavon sulfur removal process is capable of reducing the sulfur content in the tail gas to less than 100 ppm. It is proprietary process. In this system hydrogenation and hydrolysis are used to convert essentially all sulfur compounds to hydrogen sulfide. This gas is then cooled, and passed into a contactor where the hydrogen sulfide is absorbed by the redox solution and oxidized to elemental sulfur. The reduced redox solution is reoxidized by contact with air and subsequently recirculated to the contactor. Elemental sulfur is removed in the air-blowing step as a froth which is pumped to a sulfur melter to be melted under pressure, separated from the redox solution, and transferred to Byproduct Processing, System 13. The decanted redox solution is returned to the system.

The chemical reactions are:

<u>Hydrogenation and Hydrolysis</u>

$$SO_2 + 3H_2 \longrightarrow H_2S + 2H_2O$$
$$S + H_2 \longrightarrow H_2S$$
$$COS + H_2O \longrightarrow H_2S + CO_2$$
$$CS_2 + 2H_2O \longrightarrow 2H_2S + CO_2$$

3.2.8 System 8 - Process Solids Treatment

The purpose of this unit is to collect and dewater the various solids slurries, or sludges resultant from the Facility Operation for economical, environmentally acceptable disposal.

The processes involved in this system are nonproprietary and are supplied by various US vendors.

Ash and slag from the gasifier and gas cooling system, biological sludges, and solid wastes, from process condensate treatment are treated in this unit. The methods below are used to accommodate the solids treatment.

Gravity settlers separate dense solids from the waste streams.

Flot thickeners-clarifiers treat slurry from the gravity settlers. Thickener and coagulent aids are added to facilitate solid-liquid separation.

Rotary Drum Filters filter sludges from the process condensate treating systems and the float thickeners.

Recovered water is sent to the Process Condensate Treating System, and solids are conveyed to Final Solids Disposal.

3.2.9 System 9 - Incinerator

An analysis of the plant requirements led to the conclusion that no incinerator was required. Miscellaneous waste oils and tars from the Lurgi or BGC/Lurgi plants are disposed of in the tar burning boilers. Combustable solid waste from such systems as coal handling and feed preparation are disposed of via the solids disposal system.

3.2.10 System 10 - Instrumentation and Control

At the module, system, and subsystem level instrumentation and control functions are included as part of the system.

The purpose of this unit is to provide operational monitoring and control of the plant and supervisory master control of the module operations.

The system includes instrumentation to measure key characteristics of all major streams (mass flow rate, temperature, pressure, composition, density, viscosity, and others as appropriate); and to display these characteristics in a central location. A dedicated computer and alarm systems are provided to record stream characteristics and identify conditions that should be brought to the unit operators' attention. Telecommunications capabilities are provided to communicate with unit operators and general facilities (System 19). All major alarms will be redundant, one on the data acquisition system and one hard-wired alarm.

3.2.11 System 12 - Solid Waste Recycling/Disposal

The purpose of this unit is to store solid waste generated by facility operation during the facility life.

This is a non-proprietary system.

This system consists of a lined impounding pit sized to contain 20 years of solid waste. It includes the conveyor system to move the solids to the pit and a leachate recovery area to recover the pump leachate to the process condensate system.

3.2.12 System 13 - Byproduct Processing

This system receives byproduct sulfur from System 5 and ammonia from System 18 and provides products to sales. More specific descriptions are given with later sections of the report.

3.2.13 System 14 - Plant Power System

This system is generally designed to receive medium voltage electrical power (4.16 KV, 6.9 KV or 13.8 KV) and provide the following functions:

- Develop the necessary voltage stepdown arrangement for plant requirements
- Distribute the necessary power to the plant equipment.

This is non-proprietary equipment and is supplied by several U.S. vendors.

TVA's incoming substation transformers receive power from its prevalent distributed voltage switching station and step down this voltage to a medium voltage to supply the plant electrical power requirement for motors, heaters, lighting, and other miscellaneous loads.

The Medium Voltage Electrical Distribution System is a secondary selective system (double ended supply) with several medium voltage buses. Each medium voltage bus receives power from its respective incoming substation transformer through an incoming breaker and supplies power to the medium voltage distribution system through the feeder breakers.

The Low Voltage Electrical Distribution System typically consists of multiple 480 V double ended load centers and 480 V motor control centers (MCC's) supplying the power to 480 V loads throughout the plant. Two load centers are interconnected through a normally open tie breaker. In the event of loss of one load center transformer or its feeder, the 480 V loads of the affected load center are fed by the second load center through the tie breaker.

Each load center consists of an incoming line section, load center transformer, and low voltage section with metal enclosed draw out power circuit breakers.

Load center transformers are air cooled, dry type, $150^{o}F$ temperature rise, with delta connected primaries and wye connected secondaries. All load center feeder circuit breakers are 1600A frame and 50,000A RMS symmetrical interrupting capacity. The 480 V motor feeder breakers are electrically operated with instantaneous and long time trip units.

480 V MCC's consist of starters, feeder circuit breakers and control devices, assembled in a common structure with horizontal and vertical buses.

A 125 Volt DC System supplies control power for medium voltage and 480 V volt plant switchgear control, protective relaying and annuciation. The system also supplies power for emergency lighting.

3.2.14 System 15 - Steam Generation/Distribution

Steam Generation/Distribution provides a means for recovering waste heat from the plant process systems while providing process steam requirements. The system consists of steam generation (process and boilers), steam distribution, condensate recovery, and boiler feed water distribution. More specific systems are described in other sections.

3.2.15 System 16 - Water Supply

The Raw Water Treatment Unit is designed to provide treated and untreated water for the following facility water systems:

Fire Water
Service Water
Potable Water
Cooling Water
Boiler Feedwater

Raw water is pumped from the river to a Fire Water-Raw Water Storage tank.

The Raw Water-Firewater Storage Tank provides surge capacity for Water Treatment as well as storage capacity for firewater. During an emergency, firewater is pumped from the tank to the firewater header system. The firewater pumps are motor driven and have a diesel engine driven spare. The spare pump is equipped with automatic start-up capability in case of power failure.

The raw water is pumped from the Raw Water-Firewater Storage Tank to the Softener-Clarifier. Lime, alum, and polyelectrolyte from the Clarifier Bulk Chemical Storage and Feed System are added to the Softener-Clarifier, which is equipped with an internal flocculation mechanism. The alum and polyelectrolyte aid in the removal of suspended solids from the raw water. Lime is added during the clarification step to "cold soften" the raw water. Chlorine is added to the raw water to inhibit algae growth in the clarifier and sand filters and reduce organic contamination.

The underflow from the clarifier is a one wt percent sludge and is pumped to solids treatment for further processing.

The clarified and softened raw water from the Softener-Clarifier flows to the Self-Backwashing Sandfilters where additional suspended solids are removed. A pressure differential across the filter bed initiates the backwash cycle. The backwash flows by gravity to the Sandfilter Backwash Sump and is recycled to the Softener-Clarifier. The filtered water flows to the Filtered Water Storage Tank and is utilized as cooling tower make-up for the Process Cooling Tower as service water for general plant use, as feed to the Demineralizer Package, and as feed to the potable water system.

Water intended for potable services is chlorinated and again filtered to meet American Water Works Association (AWWA) standards and stored in a tank sized to hold a day's potable water requirements. The chlorine residual is maintained at 0.5-1.0 PPM free chlorine in the tank.

Filtered water intended as feed to the Demineralizer Package is injected with Sodium Sulfide to remove trace amounts of chlorine which adversely affect the Demineralizer resins and after filtered through activated carbon to remove any remaining organic contaminants and dissolve iron.

In the demineralizer, the mineral salts present in the water are removed by ion exchange. A two-step demineralization system, utilizing strong cation and strong anion exchangers in series, is provided. A degasifier following the strong cation and magnesium, which the anion exchangers remove anions such as chloride and sulfate. The strong anion exchanger also removes silica. The degasifier is provided to remove carbon dioxide and other dissolved gases.

A mixed bed polisher is provided to remove silica to 0.02 PPM and to polish returned turbine condensate for reuse.

The demineralized water and condensate is preheated to 220-225^{o}F before being pumped into the boiler feedwater deaerators.

Acid, stored in the Acid Tank, is used to regenerate the cation exchangers. Caustic, stored in the Caustic Tank, is used to regenerate the anion exchangers.

Both the Acid and Caustic tanks have pumps and metering devices to control the flow of regenerants to the demineralizer package.

The Boiler Feedwater Deaerating heaters operate at 30 psig and 250^{o}F. The Deaerators reduce the oxygen content of BFW to 0.005 cc/lites.

Hydrazine or sodium sulfite is injected into the storage compartment of the deaerators for chemical scavenging of any residual oxygen. Morpholine is injected into the suction of the boiler feed-water pumps to protect the condensate systems.

3.2.16 System 17 - Water Cooling

The purpose of this unit is to provide cooling water to the various process users in the facility.

This is a non-proprietary system and is supplied by several US vendors.

The cooling tower system includes the tower and fans, sidestream filters, circulating water pumps, cold water basis, blowdown system, chemical addition equipment, and distribution system.

Cooling water is pumped from the cold water basis, through the distribution system to the process heat exchangers where low-level, sensible heat is picked up, and back to the cooling tower. The cooling tower rejects low-level heat by evaporative cooling to air drawn through the cooling tower by the cooling tower fans.

A portion of the circulating water is passed through side stream filters to reduce loading to suspended solids, dirt and scale.

The dissolved solids level of the cooling water is maintained by a continuous blowdown stream to the process condensate system. Water level in the cooling tower basis is maintained by continuous make up of the clean water from the raw water treatment system.

The blowdown stream is passed through a blowdown treatment system to recover chromate ions via ion exchange or by chemical reduction to chromium hydroxide and is sent to waste treatment for disposal.

Chlorine is added to the cooling water on a routine periodic basis to prevent algae growth. Chemical algicides are added periodically to further eliminate algae growth. Sulfuric acid is added to control pH and zinc and chromate inhibitors are added to the cooling water for corrosion control. Occasionally a polyphosphate dispersant is added to enhance the action of the inhibitors.

3.2.17 System 18 - Waste Water Treatment

Waste Water Treatment receives all plant liquid effluent streams, recovers ammonia and hydrocarbon byproducts and treats the water for recycle. Zero aqueous discharge is designed into the plant. More specific descriptions are given in other sections.

3.2.18 System 19 - General Facilities

The purpose of this unit is to provide equipment or services to support the Gasification Facility at the facility level.

The equipment and Services provided in this unit are non-proprietary.

This unit is a general facility category and provides the following equipment and services:

- Administration Building
- Laboratories
- Change Rooms
- Warehouses
- Maintenance Buildings
- Operation Centers
- Security Offices
- Plant Air Facility
- Fire House
- Visitor Reception
- Plant Fencing
- Plant Lighting
- Roads, Bridges
- Docking Facilities
- Interconnection Pipe Ways
- Fire Protection Network
- Flare Stacks and Headers
- Plant Instrument Air Compressors
- Environmental Monitoring
- Site Preparation.

4.0 LURGI FACILITY DEFINITION DESIGN

The Lurgi Facility Definition Design processes 20,000 TPD of Kentucky No. 9 coal in four identical modules. The basis of the design is the Lurgi moving bed coal gasifier. The configuration of each module is divided for purposes of engineering studies and cost analysis into a number of interconnected systems. Drawing Number 521-L-001 is a block flow diagram of the design. These systems are listed in Table 4.1. The systematic analysis which led to the choice of systems given in Section 3.0 applies to this design. In addition a selected number of trade studies specific to Lurgi based gasification were conducted in order to complete the choice of technologies for each system. Table 4.5 gives the material balance corresponding to the block flow diagram. Tables 4.6 and 4.7 give the plant energy balance. Table 4.8 presents the operating requirements.

4.1 Lurgi System Trade Studies

The system technology distinctly associated with the Lurgi or BGC Lurgi as compared to the other gasifier processes of concern in this study are tar/oil disposition, phenol recovery, and ammonia recovery. These process requirements arise directly from the operation of a fixed bed countercurrent reactor with its relatively cool coal feed entry section wherein coal is devolatized under conditions not sufficiently severe to cause gasification of the vaporized volatile material. The low temperature also promotes the formation of ammonia as compared to the molecular nitrogen formed in hotter gasification reactors.

4.1.1 Tar/Oil Disposition Trade

Alternatives considered for the disposition of recovered tars and oil are:

a) burn in fired equipment and
b) sell as a product.

Table 4.2 presents the considerations relative to each alternative. Based on these considerations, lack of dependable data on product quality/quantity to be expected as a basis for sales and previous team experience with difficulty in finding suitable markets, the decision is to burn the tar/oil product in the boilers of the Steam Generation and Distribution System.

4.1.2 Phenol Recovery Trades

The alternatives considered for phenol recovery include:

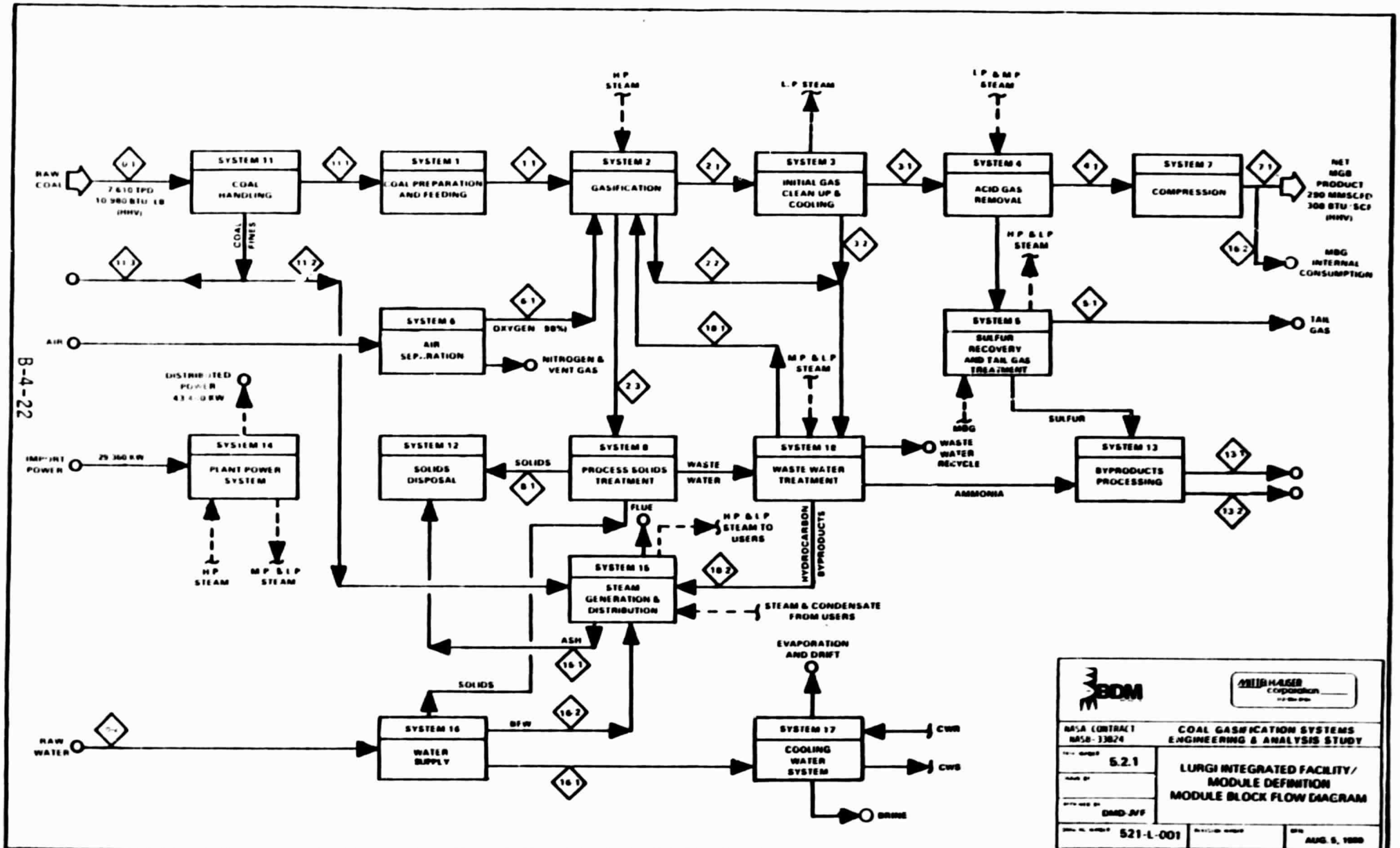
a) do no recover (bio-oxidation)
b) Phenosolvan process
c) Chempro process.

TABLE 4.1. LIST OF SYSTEMS, LURGI PLANT

SYSTEM NO.	NUMBER OF COST UNITS PER MODULE	PER FACILITY	SYSTEM DESCRIPTION
1	1	4	COAL PREPARATION & FEEDING
2	7	28	GASIFICATION
3	1	4	INITIAL GAS CLEANUP & COOLING
4	1	4	ACID GAS REMOVAL
5	1	5	SULFUR RECOVERY
6	1	5	AIR SEPARATION
7	1	4	COMPRESSION
8	1	4	PROCESS SOLIDS TREATMENT
10	-	1	INSTRUMENTATION AND CONTROL
11	-	1	COAL HANDLING
12	-	1	SOLIDS DISPOSAL
13	1	4	BYPRODUCT PROCESSING
14	1	4	PLANT POWER SYSTEM
15	2	8	STEAM GENERATION/DISTRIBUTION
16	1	4	RAW WATER MAKEUP
17	1	4	COOLING WATER SYSTEM
18	1	4	WASTE WATER TREATMENT
19	-	1	GENERAL FACILITIES

TABLE 4.2
TAR/OIL DISPOSITION TRADES
LURGI AND BGC/SLAGGER

ALTERNATIVE NO.	1	2
DESCRIPTION	SELL AS BYPRODUCT	USE AS FUEL
MEETS PERFORMANCE CRITERIA	Yes	Yes
RELATIVE CAPITAL COST	Low	Higher
RELATIVE ENERGY CONSUMPTION	Lowest	Higher
PROPRIETARY	No	No
COMMERCIALLY PROVEN	-	Yes
APPLIED DEVELOPMENT NEEDS	-	-
COULD DELAY IMPLEMENTATION	Yes	No
DATA AVAILABILITY		
SYSTEM-LEVEL DESIGN	Yes	Yes
COST	Yes	Yes
SUBSYSTEM LEVEL DESIGN	Yes	No
COST	Yes	No
RELATIVE COMPLEXITY	Low	Moderate
RELATIVE OPERATING COST	-	-
POTENTIAL ENVIRONMENTAL PROBLEM	-	SO_X, NO_X
BYPRODUCT MARKETABILITY	Questionable	-


RAW COAL
7 610 TPD
10 980 BTU/LB
(HHV)
SYSTEM 11
COAL HANDLING
COAL FINES
SYSTEM 1
COAL PREPARATION AND FEEDING
H P STEAM
SYSTEM 2
GASIFICATION
L P STEAM
SYSTEM 3
INITIAL GAS CLEAN UP & COOLING
L P & M P STEAM
SYSTEM 4
ACID GAS REMOVAL
SYSTEM 7
COMPRESSION
NET MGB PRODUCT
290 MMSCFD
308 BTU/SCF
(HHV)
MBG INTERNAL CONSUMPTION
H P & L P STEAM
SYSTEM 6
AIR SEPARATION
OXYGEN 98%
NITROGEN & VENT GAS
AIR
SYSTEM 5
SULFUR RECOVERY AND TAIL GAS TREATMENT
TAIL GAS
MBG
SULFUR
M P & L P STEAM
DISTRIBUTED POWER
IMPORT POWER
29 360 KW
SYSTEM 14
PLANT POWER SYSTEM
H P STEAM
M P & L P STEAM
SYSTEM 12
SOLIDS DISPOSAL
SOLIDS
SYSTEM 8
PROCESS SOLIDS TREATMENT
WASTE WATER
SYSTEM 10
WASTE WATER TREATMENT
WASTE WATER RECYCLE
SYSTEM 13
BYPRODUCTS PROCESSING
AMMONIA
FLUE
H P & L P STEAM TO USERS
HYDROCARBON BYPRODUCTS
SYSTEM 15
STEAM GENERATION & DISTRIBUTION
STEAM & CONDENSATE FROM USERS
ASH
SOLIDS
EVAPORATION AND DRIFT
RAW WATER
SYSTEM 16
WATER SUPPLY
BFW
SYSTEM 17
COOLING WATER SYSTEM
CWR
CWS
BRINE
BDM
NASA CONTRACT NAS8-33824
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
5.2.1
LURGI INTEGRATED FACILITY/ MODULE DEFINITION MODULE BLOCK FLOW DIAGRAM
DMD-JVF
521-L-001
AUG. 5, 1980

The considerations applicable to these alternatives are presented in Table 4.3. Based on these considerations and the fact that:

- Phenol extraction is only needed with Lurgi based facilities and Lurgi generally prefers or insists on use of Phenosolvan
- Direct biological oxidation is very risky due to very high BOD concentration
- Phenosolvan and Chempro are very similar in overall process approach.

The decision is to use Phenosolvan to recover phenols and to burn them in the Steam Generation and Distribution System.

4.1.3 Ammonia Recovery Trades

The process alternatives considered for ammonia recovery include:

a) Chevron WWT
b) Phosam-W
c) stripping only

The considerations applicable to these alternatives are presented in Table 4.1. Based on these considerations and the fact that

- Phosam-W has been found to be the economic choice from past direct comparisons when an ammonia producing gasifier is used
- Power costs are higher for the WWT process
- If ammonia is not recovered severe problems can occur in the sulfur recovery plant
- Phosam-W is proven on dirty gas similar to coal gasification products.

The decision is to use Phosam-W to recover ammonia from sour water.

4.2 System Descriptions

The systems shown in the block flow diagram are catagorized as similar in description to those given in Section 3.0 or as specific to the Lurgi based plant. Systems in the later catagory are:

- System 1 - Coal Preparation and Feed
- System 2 - Coal Gasification
- System 3 - Initial Gas Cleaning and Cooling

TABLE 4.3
PHENOL RECOVERY TRADES
LURGI AND BGC/SLAGGER

ALTERNATIVE NO.	1	2	3
DESCRIPTION	DO NOT RECOVER (BIO-OXIDATION)	PHENO-SOLVAN	CHEM-PRO
MEETS PERFORMANCE CRITERIA	Yes	Yes	Yes
RELATIVE CAPITAL COST	Higher	Lower	Lower
RELATIVE ENERGY CONSUMPTION	Higher	Lower	Lower
PROPRIETARY	No	Yes	Yes
COMMERCIALLY PROVEN	Yes	Yes	Yes
APPLIED DEVELOPMENT NEEDS	Some	No	No
COULD DELAY IMPLEMENTATION	Yes	Yes	Yes
DATA AVAILABILITY			
SYSTEM-LEVEL DESIGN	Yes	Yes	Yes
COST	Yes	Yes	Yes
SUBSYSTEM LEVEL DESIGN	Yes	No	No
COST	Yes	No	No
RELATIVE COMPLEXITY	Lower	Higher	Higher
RELATIVE OPERATING COST	Higher	Lower	Lower
POTENTIAL ENVIRONMENTAL PROBLEM	Higher	Lower	Lower
BYPRODUCT MARKETABILITY	No	Possible*	Possible*

* At least will have fuel value

TABLE 4.4
AMMONIA RECOVERY TRADES

ALTERNATIVE NO.	1	2	3
DESCRIPTION	CHEVRON WWT	PHOSAM -W	STRIPPING ONLY
MEETS PERFORMANCE CRITERIA	Yes	Yes	Yes
RELATIVE CAPITAL COST	Highest	Mid	Lowest
RELATIVE ENERGY CONSUMPTION	Highest	Mid	Lowest
PROPRIETARY	Yes	Yes	No
COMMERCIALLY PROVEN	Yes	Yes	Yes
APPLIED DEVELOPMENT NEEDS	Slight	Slight	Slight
COULD DELAY IMPLEMENTATION	No	No	No
DATA AVAILABILITY			
SYSTEM-LEVEL DESIGN	Yes	Yes	Yes
COST	Yes	Yes	Yes
SUBSYSTEM LEVEL DESIGN	No	No	Yes
COST	No	No	Yes
RELATIVE COMPLEXITY	Highest	Mid	Lowest
ANNUALIZED COST	-	Lowest	-
POTENTIAL ENVIRONMENTAL PROBLEM	None	None	High
BYPRODUCT MARKETABILITY	Yes	Yes	No

- System 6 - Air Separation
- System 7 - Compression
- System 15 - Steam Generation/Distribution
- System 18 - Waste Water Treatment

4.2.1 System 1 - Coal Preparation and Feeding

This system receives 2"x0 coal from System 11, Coal Handling and crushes it to maximum 1 inch in size. Coal in the size range 1"x28 mesh is conveyed to the Coal Gasification Section. Minus 28 mesh coal is recovered and used as supplemental fuel in the Steam Generation and Distribution System. Excess coal fines are sold as a plant byproduct.

4.2.2 Coal Gasification

The Lurgi gasifier, a dry ash, gravitating bed type, is commercially available from Lurgi Kohle and Mineraloetechnik.

The gasifier is essentially a refractory-lined, water-jacketed cylindrical shell operating at 30 atmospheres pressure. Coal is received from Coal Preparation into lock hoppers situated above the gasification reactors. Coal is fed to the gasifier by gravitational feed from the lock hoppers and spread over the top of the bed of coal. The bed of coal gravitates from top to bottom. The coal flows countercurrent to the gasification medium (oxygen and steam). The steam generated in the water jacket is used in gasification. Dry ash is removed continuously by a rotating grate into a semi-automatic ash lock.

The gas leaves the gasifier at a temperature of 650 degrees F. The gas is washed in a scrubbing cooler where it is cooled and water saturated. Traces of coal dust contained in the gas are removed via the action of heavy tar condensation on the particles in the scrubber. This mixture of tar-dust can be recycled to the gasifier. The scrubber is an integral part of the waste heat boiler system and the gas leaves the waste heat boiler at 399 degrees F. At this point, the gas consists primarily of CO_2, CO, H_2 and CH_4, and some H_2S. The proportion of these components depend on the type of coal and the operating conditions. The gas also contains tar, oil, light naphtha, other hydrocarbons, and sulfur compounds.

4.2.3 System 3 - Initial Gas Cleaning and Cooling

Raw gas from the Coal Gasification System enters the Initial Gas Cleaning and Cooling System from the waste heat boiler in the Coal Gasification Systems. Since this stream still contains ammonia, carbon dioxide, hydrogen sulfide, and oil and water vapor, special design considerations are required to prevent plugging and excessive fouling of cooling surfaces. This design including vertical tubes with tube walls washed with reinjected gas liquor is based on proprietary technology owned by Lurgi Kohle and Mineraloeltechnik, GmbH. Gas leaves this system at 100^{o}F. Water effluent containing tar, oil, ammonia and acid gases is sent to Waste Water Treating.

4.2.4 Air Separation

This system is described in Section 3 with final compression of the oxygen to 515 psig.

4.2.5 System 7 - Compression

This system receives gas at 412 psig from the Acid Gas Removal System and boosts the pressure to 600 spig for plant discharge.

4.2.6 System 15 - Steam Generation and Distribution

The Steam Generation and Distribution System produces process steam from the gasifier jackets and high pressure steam from the waste heat boiler in the Coal Gasification System and medium and low pressure steam in the sulfur recovery system. Additional steam requirements are produced by high pressure steam boilers fired with tar, oil and phenolic liquids supplemented with coal fines from the Coal Preparation and Feed System. Process steam requirements are primarily Coal Gasification, Acid Gas Removal (regenerator reboiler and solvent chilling unit) and Waste Water Treating Systems. High pressure steam is let down through back pressure turbines to supply additional low and medium pressure steam for processing and miscellaneous plant heat requirements. A condensate recovery, deaerator, and boiler feed water distribution network complete this system.

4.2.7 System 18 - Waste Water Treating

The Waste Water Treatment System is designed for Tar/Oil separation, process condensate treatment, phenol recovery, ammonia recovery, and return of treated water to the plant. Solids removed in this system are put in the Solids Disposal System.

Tar/oil separation is accomplished in gravity settling tanks. The tar oil product is used as fuel in the Steam Generation and Distribution System. Phenolic compounds are recovered in a Phenosolvan unit. Phenolic compounds are to also be burned as fuel pending development of a makret. Ammonia is recovered in a Phosom-W unit and sent to the Byproduct Process System for sale.

Streams containing miscellaneous free and dissolved oil are treated in a gravity separator utilizing an emolsion breaker and heat to separate the oil water mixture.

Streams containing a high as pH are treated with sulfuric acid or lime as appropriate in equalization basins. Neutralized brines are evaporated with the concentrated solids goild solids disposal. Recovered treated water is used as makeup for the cooling tower and raw water supply.

TABLE 4.5

MATERIAL BALANCE
LURGI PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			0-1		0-2		1-1	
STREAM ID			RAW COAL		RAW WATER		GASIFIER FEED COAL	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01		386,033.		-		253,635.
HYDROGEN	H_2	2.016		27,282.		-		17,925.
OXYGEN	O_2	32.0		8,769.		-		5,762.
NITROGEN & ARGON	N_2	28.016		36,378.		-		23,902.
SULFUR	S	32.06		23,514.		-		15,449.
CHLORINE	Cl	35.453		751.		-		494.
CARBON MONOXIDE	CO	28.01		-		-		-
CARBON DIOXIDE	CO_2	44.01		-		-		-
METHANE	CH_4	16.042		-		-		-
ETHYLENE	C_2H_4	28.052		-		-		-
ETHANE	C_2H_6	30.068		-		-		-
PROPYLENE	C_3H_6	42.078		-		-		-
PROPANE	C_3H_8	44.094		-		-		-
HYDROGEN SULFIDE	H_2S	34.076		-		-		-
CARBONYL SULFIDE	COS	60.075		-		-		-
CARBON DISULFIDE	CS_2	76.13		-		-		-
SULFUR DIOXIDE	SO_2	64.06		-		-		-
NITROUS OXIDE	NO	30.008		-		-		-
AMMONIA	NH_3	17.031		-		-		-
HYDROGEN CYANIDE	HCN	27.026		-		-		-
HYDROGEN CHLORIDE	HCl	36.461		-		-		-
NAPHTHA	-			-		-		-
TAR & OIL	-			-		-		-
ASH	-			90,788.		-		59,650.
OTHER SOLIDS				-		-		-
SUBTOTAL, DRY				573,515.		-		376,817.
WATER	H_2O	18.016		60,652.		-		39,850.
TOTAL, WET				634,167.		-		416,667.
GAS MOLECULAR WEIGHT				-		-		-
TEMPERATURE, °F				-		-		-
PRESSURE, PSIA				-		-		-
SCFH				-		-		-
GPM				-		2,083.		-

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TABLE 4.5 (Continued)

MATERIAL BALANCE
LURGI PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			1-2		1-3		13-1	
STREAM ID			BOILER COAL		COAL FINES EXPORT		SULFUR BYPRODUCT	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01		50,518.		81,880.		-
HYDROGEN	H_2	2.016		3,570.		5,787.		-
OXYGEN	O_2	32.0		1,148.		1,859.		-
NITROGEN & ARGON	N_2	28.016		4,761.		7,715.		-
SULFUR	S	32.06		3,077.		4,988.		14,754.
CHLORINE	Cl	35.453		98.		159.		-
CARBON MONOXIDE	CO	28.01		-		-		-
CARBON DIOXIDE	CO_2	44.01		-		-		-
METHANE	CH_4	16.042		-		-		-
ETHYLENE	C_2H_4	28.052		-		-		-
ETHANE	C_2H_6	30.068		-		-		-
PROPYLENE	C_3H_6	42.078		-		-		-
PROPANE	C_3H_8	44.094		-		-		-
HYDROGEN SULFIDE	H_2S	34.076		-		-		-
CARBONYL SULFIDE	COS	60.075		-		-		-
CARBON DISULFIDE	CS_2	76.13		-		-		-
SULFUR DIOXIDE	SO_2	64.06		-		-		-
NITROUS OXIDE	NO	30.008		-		-		-
AMMONIA	NH_3	17.031		-		-		-
HYDROGEN CYANIDE	HCN	27.026		-		-		-
HYDROGEN CHLORIDE	HCl	36.461		-		-		-
NAPHTHA	-			-		-		-
TAR & OIL	-			-		-		-
ASH	-			11,881.		19,257.		-
OTHER SOLIDS				-		-		-
SUBTOTAL, DRY				75,053.		121,645.		14,754.
WATER	H_2O	18.016		7,937.		12,865.		-
TOTAL, WET				82,990.		134,510.		-
GAS MOLECULAR WEIGHT				-		-		-
TEMPERATURE, °F				-		-		-
PRESSURE, PSIA				-		-		-
SCFH				-		-		-
GPM				-		-		-

TABLE 4.5 (Continued)

MATERIAL BALANCE
LURGI PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			13-2		16-1		16-2	
STREAM ID			ANHYDROUS AMMONIA		COOLING TOWER MAKE-UP		BOILER FEED WATER	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01		-		-		-
HYDROGEN	H_2	2.016		-		-		-
OXYGEN	O_2	32.0		-		-		-
NITROGEN & ARGON	N_2	28.016		-		-		-
SULFUR	S	32.06		-		-		-
CHLORINE	Cl	35.453		-		-		-
CARBON MONOXIDE	CO	28.01		-		-		-
CARBON DIOXIDE	CO_2	44.01		-		-		-
METHANE	CH_4	16.042		-		-		-
ETHYLENE	C_2H_4	28.052		-		-		-
ETHANE	C_2H_6	30.068		-		-		-
PROPYLENE	C_3H_6	42.078		-		-		-
PROPANE	C_3H_8	44.094		-		-		-
HYDROGEN SULFIDE	H_2S	34.076		-		-		-
CARBONYL SULFIDE	COS	60.075		-		-		-
CARBON DISULFIDE	CS_2	76.13		-		-		-
SULFUR DIOXIDE	SO_2	64.06		-		-		-
NITROUS OXIDE	NO_2	30.008		-		-		-
AMMONIA	NH_3	17.031		5,604.		-		-
HYDROGEN CYANIDE	HCN	27.026		-		-		-
HYDROGEN CHLORIDE	HCl	36.461		-		-		-
NAPHTHA	-			-		-		-
TAR & OIL	-			-		-		-
ASH	-			-		-		-
OTHER SOLIDS				-		-		-
SUBTOTAL, DRY				5,604.		-		-
WATER	H_2O	18.016		-		-		699,670.
TOTAL, WET				-		-		-
GAS MOLECULAR WEIGHT				-		-		-
TEMPERATURE, °F				-		-		-
PRESSURE, PSIA				-		-		-
SCFH				-		-		-
GPM				-		501.		1,398.

TABLE 4.5 (Continued)

MATERIAL BALANCE
LURGI PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			15-1		18-1		18-2	
STREAM ID			BOILER ASH TO DISPOSAL		RECYCLE GAS LIQUOR		HYDROCARBON BY-PRODUCTS TO BOILER	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01		-		-		-
HYDROGEN	H_2	2.016		-		-		-
OXYGEN	O_2	32.0		-		-		-
NITROGEN & ARGON	N_2	28.016		-		-		-
SULFUR	S	32.06		-		-		-
CHLORINE	Cl	35.453		-		-		-
CARBON MONOXIDE	CO	28.01		-		-		-
CARBON DIOXIDE	CO_2	44.01		-		-		-
METHANE	CH_4	16.042		-		-		-
ETHYLENE	C_2H_4	28.052		-		-		-
ETHANE	C_2H_6	30.068		-		-		-
PROPYLENE	C_3H_6	42.078		-		-		-
PROPANE	C_3H_8	44.094		-		-		-
HYDROGEN SULFIDE	H_2S	34.076		-		-		-
CARBONYL SULFIDE	COS	60.075		-		-		-
CARBON DISULFIDE	CS_2	76.13		-		-		-
SULFUR DIOXIDE	SO_2	64.06		-		-		-
NITROUS OXIDE	NO_2	30.008		-		-		-
AMMONIA	NH_3	17.031		-		5,738.		-
HYDROGEN CYANIDE	HCN	27.026		-		-		-
HYDROGEN CHLORIDE	HCl	36.461		-		520.		-
NAPHTHA	-			-		4,124.		4,028.
TAR & OIL	-			-				21,631.
ASH	-			11,491.		-		-
OTHER SOLIDS				-		-		-
SUBTOTAL, DRY				11,491.		10,382.		25,659.
WATER	H_2O	18.016		-		669,711.		1,139.
TOTAL, WET				-		680,093.		26,789.
GAS MOLECULAR WEIGHT				-		-		-
TEMPERATURE, °F				-		205.		-
PRESSURE, PSIA				-				-
SCFH				-		-		-
GPM				-		1,415.		51.

TABLE 4.5 (Continued)

MATERIAL BALANCE
LURGI PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			11-1		2-1		2-2	
STREAM ID			GASIFIER COAL		RAW GAS		TARRY GAS LIQUOR	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01		253,635.		-		-
HYDROGEN	H_2	2.016		17,925.		30,030.		-
OXYGEN	O_2	32.0		5,762.		-		-
NITROGEN & ARGON	N_2	28.016		23,902.		3,937.		-
SULFUR	S	32.06		15,449.		-		-
CHLORINE	Cl	35.453		494.		-		-
CARBON MONOXIDE	CO	28.01		-		152,441.		-
CARBON DIOXIDE	CO_2	44.01		-		456,816.		-
METHANE	CH_4	16.042		-		45,815.		-
ETHYLENE	C_2H_4	28.052		-		2,376.		-
ETHANE	C_2H_6	30.068		-		3,899.		-
PROPYLENE	C_3H_6	42.078		-		-		-
PROPANE	C_3H_8	44.094		-		-		-
HYDROGEN SULFIDE	H_2S	34.076		-		15,540.		-
CARBONYL SULFIDE	COS	60.075		-		660.		-
CARBON DISULFIDE	CS_2	76.13		-		-		-
SULFUR DIOXIDE	SO_2	64.06		-		-		-
NITROUS OXIDE	NO	30.008		-		-		-
AMMONIA	NH_3	17.031		-		5,604.		5,738.
HYDROGEN CYANIDE	HCN	27.026		-		-		-
HYDROGEN CHLORIDE	HCl	36.461		-		-		1,027.
NAPHTHA	-			-		4,028.		4,124.
TAR & OIL	-			-		-		21,631.
ASH	-			59,650.		-		
OTHER SOLIDS				-		-		-
SUBTOTAL, DRY				376,817.		721,146.		-
WATER	H_2O	18.016		39,850.		869,881.		400,411.
TOTAL, WET				416,667.		1,591,027.		432,931.
GAS MOLECULAR WEIGHT				-	19.16			-
TEMPERATURE, °F				-	399.			399.
PRESSURE, PSIA				-	440			-
SCFH				-	31,518,044.			-
GPM				-	-			-

TABLE 4.5 (Continued)

MATERIAL BALANCE
LURGI PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			2-3		3-1		3-2	
STREAM ID			ASH		CRUDE GAS		OILY GAS LIQUOR	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01		2,486.		-		-
HYDROGEN	H_2	2.016		-		30,030.		-
OXYGEN	O_2	32.0		-		-		-
NITROGEN & ARGON	N_2	28.016		-		3,937.		-
SULFUR	S	32.06		-		-		-
CHLORINE	Cl	35.453		-		-		-
CARBON MONOXIDE	CO	28.01		-		152,441.		-
CARBON DIOXIDE	CO_2	44.01		-		456,816.		-
METHANE	CH_4	16.042		-		45,815.		-
ETHYLENE	C_2H_4	28.052		-		2,376.		-
ETHANE	C_2H_6	30.068		-		3,899.		-
PROPYLENE	C_3H_6	42.078		-		-		-
PROPANE	C_3H_8	44.094		-		-		-
HYDROGEN SULFIDE	H_2S	34.076		-		15,540.		-
CARBONYL SULFIDE	COS	60.075		-		660.		-
CARBON DISULFIDE	CS_2	76.13		-		-		-
SULFUR DIOXIDE	SO_2	64.06		-		-		-
NITROUS OXIDE	NO_2	30.008		-		-		-
AMMONIA	NH_3	17.031		-		-		5,604.
HYDROGEN CYANIDE	HCN	27.026		-		-		-
HYDROGEN CHLORIDE	HCl	36.461		-		-		-
NAPHTHA	-			-		-		4,028.
TAR & OIL	-			-		-		-
ASH	-			59,650.		-		-
OTHER SOLIDS				-		-		-
SUBTOTAL, DRY				62,136.		711,514.		9,632.
WATER	H_2O	18.016		-		1,342.		924,588.
TOTAL, WET				62,136.		712,856.		934,220.
GAS MOLECULAR WEIGHT				-	20.68			-
TEMPERATURE, °F				750.	100.			272.
PRESSURE, PSIA				-	430.			-
SCFH				-	13,081,479.			-
GPM				-				2,008.

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TABLE 4.5 (Continued)

MATERIAL BALANCE
LURGI PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			4-1		4-2		8-1	
STREAM ID			PRODUCT GAS TO COMPRESSION AND INTERNAL USE		ACID GAS		SOLIDS TO DISPOSAL	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01		-		-		2,486.
HYDROGEN	H_2	2.016		30,030.		-		-
OXYGEN	O_2	32.0		-		-		-
NITROGEN & ARGON	N_2	28.016		1,937.		-		-
SULFUR	S	32.06		-		-		-
CHLORINE	Cl	35.453		-		-		-
CARBON MONOXIDE	CO	28.01		152,441.		-		-
CARBON DIOXIDE	CO_2	44.01		364,646.		92,170.		-
METHANE	CH_4	16.042		45,815.		-		-
ETHYLENE	C_2H_4	28.052		2,376.		-		-
ETHANE	C_2H_6	30.068		3,899.		-		-
PROPYLENE	C_3H_6	42.078		-		-		-
PROPANE	C_3H_8	44.094		-		-		-
HYDROGEN SULFIDE	H_2S	34.076		61.		15,479.		-
CARBONYL SULFIDE	COS	60.075		300.		360.		-
CARBON DISULFIDE	CS_2	76.13		-		-		-
SULFUR DIOXIDE	SO_2	64.06		-		-		-
NITROUS OXIDE	NO	30.008		-		-		-
AMMONIA	NH_3	17.031		-		-		-
HYDROGEN CYANIDE	HCN	27.026		-		-		-
HYDROGEN CHLORIDE	HCl	36.461		-		-		-
NAPHTHA	-			-		-		-
TAR & OIL	-			-		-		-
ASH	-			-		-		59,650.
OTHER SOLIDS				-		-		120.
SUBTOTAL, DRY				603,505.		108,009.		62,256.
WATER	H_2O	18.016		312.		3,841.		6,917.
TOTAL, WET				603,817.		111,850.		69,173.
GAS MOLECULAR WEIGHT			18.95		40.41			-
TEMPERATURE, °F			57.		120			-
PRESSURE, PSIA			427.		22			-
SCFH			12,090,339.		1,050,380.			-
GPM			-		-			-

TABLE 4.5 (Continued)

MATERIAL BALANCE
LURGI PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			7-1		6-1		5-1	
STREAM ID			NET MBG PRODUCT		PROCESS OXYGEN		TAIL GAS	
	SYMBOL	FORMULA WEIGHT	LB-MOLS / HR	LBS / HR	LB-MOLS / HR	LBS / HR	LB-MOLS / HR	LBS / HR
CARBON	C	12.01		-		-		-
HYDROGEN	H_2	2.016		29,968.		-		-
OXYGEN	O_2	32.0		-		171,711.		-
NITROGEN & ARGON	N_2	28.016		3,928.		3,068.		27,8[illegible].
SULFUR	S	32.06		-		-		-
CHLORINE	Cl	35.453		-		-		-
CARBON MONOXIDE	CO	28.01		152,127.		-		-
CARBON DIOXIDE	CO_2	44.01		363,892.		-		93,[illegible].
METHANE	CH_4	16.042		45,720.		-		-
ETHYLENE	C_2H_4	28.052		2,371.		-		-
ETHANE	C_2H_6	30.068		3,892.		-		-
PROPYLENE	C_3H_6	42.078		-		-		-
PROPANE	C_3H_8	44.094		-		-		-
HYDROGEN SULFIDE	H_2S	34.076		61.		-		[illegible].1
CARBONYL SULFIDE	COS	60.075		300.		-		-
CARBON DISULFIDE	CS_2	76.13		-		-		-
SULFUR DIOXIDE	SO_2	64.06		-		-		-
NITROUS OXIDE	NO	30.008		-		-		-
AMMONIA	NH_3	17.031		-		-		-
HYDROGEN CYANIDE	HCN	27.026		-		-		-
HYDROGEN CHLORIDE	HCl	36.461		-		-		-
NAPHTHA	-			-		-		-
TAR & OIL	-			-		-		-
ASH	-			-		-		-
OTHER SOLIDS				-		-		-
SUBTOTAL, DRY				602,259.		174,779.		121,6[illegible].
WATER	H_2O	18.016		86.		-		3,8[illegible].
TOTAL, WET				602,341.		-		125,5[illegible].
GAS MOLECULAR WEIGHT					31.92		37.57	
TEMPERATURE, °F					302.		100	
PRESSURE, PSIA					515.		Ambient	
SCFH					2,077,952.		1,268,593.	
GPM					-		-	

TABLE 4.6
ENERGY BALANCE, 10^6 BTU PER HOUR
LURGI MODULE
TASK 5.2.1 INTEGRATED FACILITY/MODULE DEFINITION

	PHASE	HHV	LATENT	SENSIBLE	TOTAL
ENTHALPY BALANCE					
INLETS					
STREAM Coal	Solid	5486	-	-	5486
Air to Air Sep'n	Gas	-	8	-	8
Raw Water	Liquid	-	-	0	-
SUBTOTAL IN					5494
OUTLETS					
STREAM MBG	Gas	3728	-	-	3278
Ash	Solid	-	-	7	7
Tail Gas	Gas	-	7	2	9
Sulfur	Solid	59	-	-	59
Air Sep'n Vent	Gas	-	-	5	5
Flue Gases	Gas	-	60	74	134
Ammonia	Gas	54	-	-	54
Wastewater	Liquid	-	-	95	95
SUBTOTAL OUT					4091
NET INLET-OUTLET					1403
HEAT AND SHAFT WORK					
ELECTRIC POWER					100
SHAFT WORK					-
HEAT REJECTION			-975	-328	-1303
HEAT INPUT (STEAM)					
RADIATION/FUGITIVE LOSS					-33
SUBTOTAL NET VALUE					-1236
TOTAL ABSOLUTE VALUE					1236

BALANCE: $\frac{\text{NET ENTHALPHY + NET HEAT \& SHAFT WORK}}{\text{TOTAL ABSOLUTE VALUE OF HEAT \& SHAFT WORK}} = \frac{1403 - 1236}{1236} \times 100\% = 13.5\%$

BASIS: $60^{\circ}F$; LIQUID WATER

TABLE 4.7
CONVERSION EFFICIENCY
LURGI PROCESS
20,000 TPD FACILITY

	10^6 BTU/HR	PERCENT
INPUTS		
1. COAL TO FACILITY	27,852	
2. ELECTRIC POWER TO FACILITY	100	
OUTPUTS		
3. MBG FROM FACILITY	14,912	
4. COAL FINES FROM FACILITY	5,908	
EFFICIENCY		
COAL-TO-MBG (3 ÷ 1) x 100%		53.5%
OVERALL PRODUCT EFFICIENCY 3 ÷ (1 + 2) x 100%		53.4%
OVERALL FACILITY EFFICIENCY 3 + 4 ÷ (1 + 2) x 100%		74.48%
GASIFICATION EFFICIENCY 3 ÷ (1 + 2 - 4)		68.0%

TABLE 4.8. OPERATING REQUIREMENTS FOR EXPECTED OPERATIONS LURGI PROCESS - PER MODULE

	BASIS	UNITS
Raw Materials		
Coal Import	TPY at 100% Operation	2,777,650 TPY
Coal Fines Export	TPY at 100% Operation	838,437 TPY
Catalyst and Chemical Makeup	$/YR at 100% Operation	$470,340/YR
Utility Requirements		
Import Power	kWh/HR at 100% Operation	168,000,000
Operating Requirements		
Labor		
Supervisors	Man-Hours/YR	27,091 mh/YR
Operators	Man-Hours/YR	122,353 mh/YR
Supplies	Factored as 15% of Operating Labor Cost	
Maintenance Requirements		
Labor	Factored at 1.6% of Total Depreciable Direct Investment	
Supplies	Factored at 2.4% of Total Depreciable Direct Investment	

5.0 BGC/LURGI FACILITY DEFINITION DESIGN

The BGC/Lurgi Facility Definition Design processes 20,000 TPD of Kentucky No. 9 coal in four identical modules. The basis of the design is the BGC/Lurgi moving bed coal gasifier with slagging bottom. The configuration of each module is divided for purposes of engineering studies and cost analysis into a number of interconnected systems. Drawing Number 521-BGC-001 is a block flow diagram of the design. These systems are listed in Table 5.1. The systematic analysis which led to the choice of systems given in Section 3.0 applies to this design. In addition a selected number of trade studies specific to Lurgi based gasification were conducted in order to complete the choice of technologies for each system. Table 5.2 gives the material balance corresponding to the block flow diagram. Tables 5.3 and 5.4 give the plant energy balance. Table 5.5 contains an operation requirements summary.

5.1 BGC/Lurgi System Trade Studies

These studies are identical to those described in Section 4.1 for the Lurgi based facility.

5.2 System Descriptions

The systems shown in the block flow diagram are catagorized as similar in description to those given in Section 3.0 or as specific to the BGC/Lurgi based plant. Systems in the later catagory are:

- System 1 - Coal Preparation and Feed
- System 2 - Coal Gasification
- System 3 - Initial Gas Cleaning and Cooling
- System 6 - Air Separation
- System 7 - Compression
- System 15 - Steam Generation/Distribution
- System 18 - Waste Water Treatment

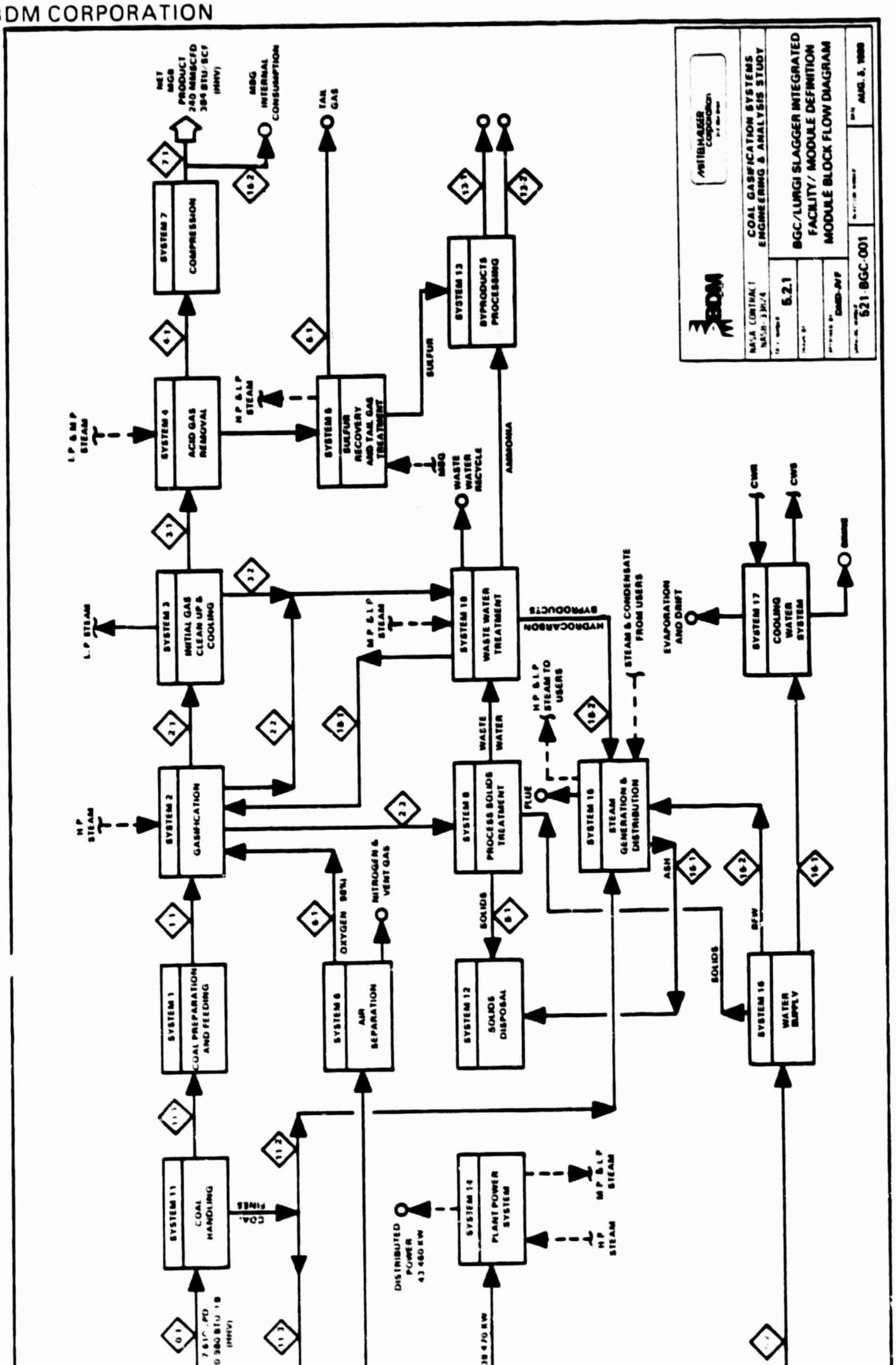
5.2.1 System 1 - Coal Preparation and Feeding

This system receives 2"x0 coal from System 11, coal handling and crushes it to maximum 1 inch in size. Coal in the size range 1"x28 mesh is conveyed to the Coal Gasification Section. Minus 28 mesh coal is recovered and used as supplemental fuel in the Steam Generation and Distribution System. Excess coal fines are sold as a plant byproduct.

There is reason to believe that the fines cut off point for the BGC/Lurgi gasifier could be less than 28 mesh due to the lower gas velocity at a given coal feed rate (less steam). However due to lack of any other data this design is based on a minus 28 mesh minimum coal size.

TABLE 5.1
SYSTEM DEFINITION
BGC/LURGI PROCESS

SYSTEM NO.	NUMBER OF COST UNITS PER MODULE	PER FACILITY	SYSTEM DESCRIPTION
1	1	4	COAL PREPARATION & FEEDING
2	3	12	GASIFICATION
3	1	4	INITIAL GAS CLEANUP & COOLING
4	1	4	ACID GAS REMOVAL
5	1	5	SULFUR RECOVERY
6	1	5	AIR SEPARATION
7	1	4	COMPRESSION
8	1	4	PROCESS SOLIDS TREATMENT
11	1	1	COAL HANDLING
12	1	4	SOLIDS DISPOSAL
13	1	4	BYPRODUCT PROCESSING
14	1	4	PLANT POWER SYSTEM
15	2	8	STEAM GENERATION/DISTRIBUTION
16	1	4	RAW WATER MAKEUP
17	1	4	COOLING WATER SYSTEM
18	1	4	WASTE WATER TREATMENT
19	1	1	GENERAL FACILITIES


SYSTEM 11
COAL HANDLING
SYSTEM 1
COAL PREPARATION AND FEEDING
SYSTEM 2
GASIFICATION
SYSTEM 3
INITIAL GAS CLEAN UP & COOLING
SYSTEM 4
ACID GAS REMOVAL
SYSTEM 7
COMPRESSION
SYSTEM 5
SULFUR RECOVERY AND TAIL GAS TREATMENT
SYSTEM 6
AIR SEPARATION
SYSTEM 14
PLANT POWER SYSTEM
SYSTEM 12
SOLIDS DISPOSAL
SYSTEM 8
PROCESS SOLIDS TREATMENT
SYSTEM 10
WASTE WATER TREATMENT
SYSTEM 13
BYPRODUCTS PROCESSING
SYSTEM 15
STEAM GENERATION & DISTRIBUTION
SYSTEM 16
WATER SUPPLY
SYSTEM 17
COOLING WATER SYSTEM
RAW COAL
RAW WATER
AIR
IMPORT POWER
DISTRIBUTED POWER
43 460 KW
NET MGB PRODUCT
240 MMSCFD
384 BTU/SCF
(HHV)
MBG INTERNAL CONSUMPTION
TAIL GAS
COAL FINES
OXYGEN 98%
NITROGEN & VENT GAS
H P STEAM
L P STEAM
L P & M P STEAM
H P & L P STEAM
M P & L P STEAM
H P & L P STEAM TO USERS
STEAM & CONDENSATE FROM USERS
SOLIDS
WASTE WATER
WASTE WATER RECYCLE
AMMONIA
SULFUR
HYDROCARBON BYPRODUCTS
FLUE
ASH
BFW
CWR
CWS
EVAPORATION AND DRIFT
NASA CONTRACT
6.2.1
COAL GASIFICATION SYSTEMS ENGINEERING & ANALYSIS STUDY
BGC/LURGI SLAGGER INTEGRATED FACILITY/ MODULE DEFINITION MODULE BLOCK FLOW DIAGRAM
521-BGC-001

5.2.2 Coal Gasification

This unit converts coal into medium heating value crude synthesis gas by partial oxidation in the presence of steam. The reaction takes place during countercurrent flow in a moving bed. The crude gas leaving the gasifier is scrubbed, quenched and saturated by gas liquor to remove coal dust and heavy tar. This multi-phase steam enters a waste heat exchanger for cooling and further condensation of heavier hydrocarbons prior to further processing.

This design is based on proprietary technolgoy held by Lurgi Kohle and Mineraloeltechnik, GmbH and British Gas Corporation.

In the process the coal and flux, entering the top of the gasifier, descends in a moving bed in countercurrent flow to the steam, oxygen and produced gas. While traveling from the top to the bottom of the gasifier, the coal is dried, devolatilized, and gasified. The heat required for these three steps is supplied by the exothermic reaction between the carbon in the coal and the oxygen in the bottom of the gasifier. Flux is added to form a low melting temperature eutectic.

As the produced gas passes through the coal bed, its final composition is determined by the following:

- Exothermic and endothermic reactions occurring simultaneously in the gasification zone,
- Formation of hydrocarbons, phenols, fatty acids, and minor organic compounds in the devolatilization zone, and
- Evaporation of coal moisture in the drying zone.

After leaving the gasifier the raw gas is scrubbed and cooled in the wash cooler scrubbers and the waste heat exchanger.

The coal and flux are fed to the coal bunkers by a belt conveyer system. The feed chutes at the bottom of the coal bunkers control the flow of coal into the coal locks. Each gasifier has two coal locks that operate automatically on a cyclic basis. There coal locks are pressurized with an inert gas and feed alternately the coal surge vessel.

The gas released during depressurization and the gas displaced during filling of the coal locks contains a small amount of coal dust. The dust is removed prior to disposal of the streams.

In the bottom of the gasifier the coal ash melts as a eutectic with the added flux to form slag. The molten slag collects at the bottom and is tapped intermittently through a tap hole into the quench vessel. In the quench vessel the slag granulates immediately upon contact with the quench water. The granulated slag falls into the slag hopper and is dumped intermittently to the Solids Treatment System.

The raw gas leaving the Gasifier requires immediate treatment to remove as many impurities as possible. The initial treatment is provided in wash coolers operating in parallel. In the wash coolers gas liquor is injected to quench and saturate the raw gas. A multi-phase stream containing raw gas, condensed hydrocarbons, dust, stream, and water flows from the wash coolers to the waste heat exchanger for additional treatment. The multi-phase flow enters the waste heat exchanger above the gas liquor level. The gas and liquor are separated, and the gas is cooled by producing low pressure (35 psig) steam. The gas liquor condensed from the raw gas is collected in a sump. A portion of the dusty gas liquor is utilized as quench water for the wash coolers with the remaining liquor being sent to the Waste Water Treating System.

5.2.3 System 3 - Initial Gas Cleaning and Cooling

Raw gas from the Coal Gasification System enters the Initial Gas Cleaning and Cooling System from the waste heat boiler in the Coal Gasification Systems. Since this stream still contains ammonia, carbon dioxide, hydrogen sulfide, and oil and water vapor, special design considerations are required to prevent plugging and excessive fouling of cooling surfaces. This design including vertical tubes with tube walls washed with reinjected gas liquor is based on proprietary technology owned by Lurgi Kohle and Mineraloeltechnik, GmbH. Gas leaves this system at $100^{o}F$. Water effluents containing tar, oil, ammonia and acid gases is sent to Waste Water Treating.

5.2.4 Air Separation

This system is described in Section 3 with final compression of the oxygen to 490 psig.

5.2.5 System 7 - Compression

This system receives gas at 412 psig from the Acid Gas Removal System and boosts the pressure to 600 spig for plant discharge.

5.2.6 System 15 - Steam Generation and Distribution

The Steam Generation and Distribution System produces process steam from the gasifier jackets and high pressure steam from the waste heat boiler in the Coal Gasification System and medium and low pressure steam in the sulfur recovery system. Additional steam requirements are produced by high pressure steam boilers fired with tar, oil and phenolic liquids supplemented with coal fines from the Coal Preparation and Feed System. Process steam requirements are primarily Coal Gasification, Acid Gas Removal (regenerator reboiler and solvent chilling unit) and Waste Water Treating Systems. High pressure steam is let down through back pressure turbines to supply additional low and medium pressure steam for processing and miscellaneous plant heat requirements. A condensate recovery, deaerator, and boiler feed water distribution network complete this system.

5.2.7 System 18 - Waste Water Treating

The Waste Water Treatment System is designed for Tar/Oil separation, process condensate treatment, phenol recovery, ammonia recovery, and return of treated water to the plant. Solids removed in this system are put in the Solids Disposal System.

Tar/oil separation is accomplished in gravity settling tanks. The tar oil product is used as fuel in the Steam Generation and Distribution System. Phenolic compounds are recovered in a Phenosolvan unit. Phenolic compounds are to also be burned as fuel pending development of a makret. Ammonia is recovered in a Phosom-W unit and sent to the Byproduct Process System for sale.

Streams containing miscellaneous free and dissolved oil are treated in a gravity separator utilizing an emolsion breaker and heat to separate the oil water mixture.

Streams containing a high or low pH are treated with sulfuric acid or lime as appropriate in equalization basins. Neutralized brines are evaporated with the concentrated solids going to solids disposal. Recovered treated water is used as makeup for the cooling tower and raw water supply.

TABLE 5.2

MATERIAL BALANCE
LURGI/BGC PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			0-1		0-2		11-1	
STREAM ID			RAW COAL FEED		RAW WATER TO WATER TREATMENT		COAL TO COAL PREPARATION & FEEDING	
	SYMBOL	FORMULA WEIGHT	LB-MOLS / HR	LBS / HR	LB-MOLS / HR	LBS / HR	LB-MOLS / HR	LBS / HR
CARBON	C	12.01		386,032.		-		253,635.
HYDROGEN	H_2	2.016		27,282.		-		17,925.
OXYGEN	O_2	32.0		36,379.		-		23,902.
NITROGEN & ARGON	N_2	28.016		8,770.		-		5,762.
SULFUR	S	32.06		23,515.		-		15,450.
CHLORINE	Cl	35.453		752.		-		494.
CARBON MONOXIDE	CO	28.01		-		-		-
CARBON DIOXIDE	CO_2	44.01		-		-		-
METHANE	CH_4	16.042		-		-		-
ETHYLENE	C_2H_4	28.052		-		-		-
ETHANE	C_2H_6	30.068		-		-		-
PROPYLENE	C_3H_6	42.078		-		-		-
PROPANE	C_3H_8	44.094		-		-		-
HYDROGEN SULFIDE	H_2S	34.076		-		-		-
CARBONYL SULFIDE	COS	60.075		-		-		-
CARBON DISULFIDE	CS_2	76.13		-		-		-
SULFUR DIOXIDE	SO_2	64.06		-		-		-
NITROUS OXIDE	NO	30.008		-		-		-
AMMONIA	NH_3	17.031		-		-		-
HYDROGEN CYANIDE	HCN	27.026		-		-		-
HYDROGEN CHLORIDE	HCl	36.461		-		-		-
NAPHTHA	-			-		-		-
TAR & OIL	-			-		-		-
ASH	-			90,787.		-		59,650.
OTHER SOLIDS				-		-		-
SUBTOTAL, DRY				573,517.		-		376,818.
WATER	H_2O	18.016		60,652.		243,316.		39,850.
TOTAL, WET				634,169.		-		416,668.
GAS MOLECULAR WEIGHT				-		-		-
TEMPERATURE, °F				-		-		-
PRESSURE, PSIA				-		-		-
SCFH				-		-		-
GPM				-		486.		-

TABLE 5.2 (Continued)

MATERIAL BALANCE
LURGI/BGC PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			11-2		11-3		16-1	
STREAM ID			COAL FINES TO STEAM GENERATION		COAL FINES EXPORT		MAKE-UP WATER TO COOLING WATER SYSTEM	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01		15,873.		116,524.		
HYDROGEN	H_2	2.016		1,122.		8,235.		-
OXYGEN	O_2	32.0		1,496.		10,981.		-
NITROGEN & ARGON	N_2	28.016		361.		2,647.		-
SULFUR	S	32.06		967.		7,098.		-
CHLORINE	Cl	35.453		31.		227.		-
CARBON MONOXIDE	CO	28.01		-		-		-
CARBON DIOXIDE	CO_2	44.01		-		-		-
METHANE	CH_4	16.042		-		-		-
ETHYLENE	C_2H_4	28.052		-		-		-
ETHANE	C_2H_6	30.068		-		-		-
PROPYLENE	C_3H_6	42.078		-		-		-
PROPANE	C_3H_8	44.094		-		-		-
HYDROGEN SULFIDE	H_2S	34.076		-		-		-
CARBONYL SULFIDE	COS	60.075		-		-		-
CARBON DISULFIDE	CS_2	76.13		-		-		-
SULFUR DIOXIDE	SO_2	64.06		-		-		-
NITROUS OXIDE	NO	30.008		-		-		-
AMMONIA	NH_3	17.031		-		-		-
HYDROGEN CYANIDE	HCN	27.026		-		-		-
HYDROGEN CHLORIDE	HCl	36.461		-		-		-
NAPHTHA	-			-		-		-
TAR & OIL	-			-		-		-
ASH	-			3,733.		27,404.		-
OTHER SOLIDS				-		-		-
SUBTOTAL, DRY				23,583.		173,116.		-
WATER	H_2O	18.016		2,494.		8,308.		204,226.
TOTAL, WET				26,077.		191,424.		
GAS MOLECULAR WEIGHT				-		-		-
TEMPERATURE, °F				-		-		60.
PRESSURE, PSIA				-		-		-
SCFH				-		-		-
GPM				-		-		408.

TABLE 5.2 (Continued)

MATERIAL BALANCE
LURGI/BGC PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			16-2		15-1		18-1	
STREAM ID			MAKEUP WATER TO STEAM GENERATION		BOILER ASH TO SOLIDS DISPOSAL		RECYCLE GAS LIQUOR	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01		-		-		-
HYDROGEN	H_2	2.016		-		-		-
OXYGEN	O_2	32.0		-		-		-
NITROGEN & ARGON	N_2	28.016		-		-		-
SULFUR	S	32.06		-		-		-
CHLORINE	Cl	35.453		-		-		-
CARBON MONOXIDE	CO	28.01		-		-		-
CARBON DIOXIDE	CO_2	44.01		-		-		-
METHANE	CH_4	16.042		-		-		-
ETHYLENE	C_2H_4	28.052		-		-		-
ETHANE	C_2H_6	30.068		-		-		-
PROPYLENE	C_3H_6	42.078		-		-		-
PROPANE	C_3H_8	44.094		-		-		-
HYDROGEN SULFIDE	H_2S	34.076		-		-		-
CARBONYL SULFIDE	COS	60.075		-		-		-
CARBON DISULFIDE	CS_2	76.13		-		-		-
SULFUR DIOXIDE	SO_2	64.06		-		-		-
NITROUS OXIDE	NO	30.008		-		-		-
AMMONIA	NH_3	17.031		-		-		-
HYDROGEN CYANIDE	HCN	27.026		-		-		-
HYDROGEN CHLORIDE	HCl	36.461		-		-		-
NAPHTHA	-			-		-		-
TAR & OIL	-			-		-		-
ASH	-			-		3,611.		-
OTHER SOLIDS	-			-		-		-
SUBTOTAL, DRY				-		3,611.		-
WATER	H_2O	18.016		68,171.		-		450,000.
TOTAL, WET				-		-		450,000.
GAS MOLECULAR WEIGHT				-		-		-
TEMPERATURE, °F				60.		-		205.
PRESSURE, PSIA				-		-		-
SCFH				-		-		-
GPM				136.		-		936.

TABLE 5.2 (Continued)

MATERIAL BALANCE
LURGI/BGC PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			18-2		13-2		1-1	
STREAM ID			HYDROCARBON BYPRODUCTS TO STEAM GENERATION		BYPRODUCT ANHYDROUS AMMONIA		SIZED COAL TO GASIFIER	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01		-		-		253,635.
HYDROGEN	H_2	2.016		-		-		17,925.
OXYGEN	O_2	32.0		-		-		23,902.
NITROGEN & ARGON	N_2	28.016		-		-		5,762.
SULFUR	S	32.06		-		-		15,450.
CHLORINE	Cl	35.453		-		-		494.
CARBON MONOXIDE	CO	28.01		-		-		-
CARBON DIOXIDE	CO_2	44.01		-		-		-
METHANE	CH_4	16.042		-		-		-
ETHYLENE	C_2H_4	28.052		-		-		-
ETHANE	C_2H_6	30.068		-		-		-
PROPYLENE	C_3H_6	42.078		-		-		-
PROPANE	C_3H_8	44.094		-		-		-
HYDROGEN SULFIDE	H_2S	34.076		-		-		-
CARBONYL SULFIDE	COS	60.075		-		-		-
CARBON DISULFIDE	CS_2	76.13		-		-		-
SULFUR DIOXIDE	SO_2	64.06		-		-		-
NITROUS OXIDE	NO_2	30.008		-		-		-
AMMONIA	NH_3	17.031		-		5,604.		-
HYDROGEN CYANIDE	HCN	27.026		-		-		-
HYDROGEN CHLORIDE	HCl	36.461		-		-		-
NAPHTHA	-			4,028.		-		-
TAR & OIL	-			21,631.		-		-
ASH	-			-		-		59,650.
OTHER SOLIDS				-		-		-
SUBTOTAL, DRY				25,659.		5,604.		376,818.
WATER	H_2O	18.016		1,139.		-		39,850.
TOTAL, WET				26,798.		-		416,668.
GAS MOLECULAR WEIGHT				-		-		-
TEMPERATURE, °F				-		-		-
PRESSURE, PSIA				-		-		-
SCFH				-		-		-
GPM				51.		-		-

TABLE 5.2 (Continued)

MATERIAL BALANCE
LURGI/BGC PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			2-1		2-2		2-3	
STREAM ID			RAW GAS TO COOLING		TARRY GAS LIQUOR TO WASTEWATER TREATMENT		SLAG TO PROCESS SOLIDS TREATMENT	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01		-		-		1,217.
HYDROGEN	H_2	2.016		15,220.		-		-
OXYGEN	O_2	32.0		-		-		-
NITROGEN & ARGON	N_2	28.016		3,898.		-		-
SULFUR	S	32.06		-		-		-
CHLORINE	Cl	35.453		-		-		-
CARBON MONOXIDE	CO	28.01		440,023.		-		-
CARBON DIOXIDE	CO_2	44.01		38,403.		-		-
METHANE	CH_4	16.042		36,738.		-		-
ETHYLENE	C_2H_4	28.052		1,904.		-		-
ETHANE	C_2H_6	30.068		3,005.		-		-
PROPYLENE	C_3H_6	42.078		-		-		-
PROPANE	C_3H_8	44.094		-		-		-
HYDROGEN SULFIDE	H_2S	34.076		15,377.		-		-
CARBONYL SULFIDE	COS	60.075		943.		-		-
CARBON DISULFIDE	CS_2	76.13		-		-		-
SULFUR DIOXIDE	SO_2	64.06		-		-		-
NITROUS OXIDE	NO	30.008		-		-		-
AMMONIA	NH_3	17.031		5,604.		-		-
HYDROGEN CYANIDE	HCN	27.026		-		-		-
HYDROGEN CHLORIDE	HCl	36.461		-		505.		-
NAPHTHA	-			4,028.		-		-
TAR & OIL	-			-		21,631.		-
ASH	-			-		-		59,650.
OTHER SOLIDS				-		-		-
SUBTOTAL, DRY				565,143.		22,139.		60,867.
WATER	H_2O	18.016		95,062.		405,763.		-
TOTAL, WET				660,205.		427,90-.		60,867.
GAS MOLECULAR WEIGHT			20.1			-		-
TEMPERATURE, °F			299.			[illegible]		2,800.
PRESSURE, PSIA			440.			-		-
SCFH			12,464,336.			-		-
GPM			-			[illegible]		-

TABLE 5.2 (Continued)

MATERIAL BALANCE
LURGI/BGC PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			3-1		3-2		4-1	
STREAM ID			COOLED RAW GAS TO ACID GAS REMOVAL		OILY GAS LIQUOR TO WASTEWATER TREATMENT		MBG PRODUCT GAS TO COMPRESSION AND INTERNAL USE	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01		-		-		-
HYDROGEN	H_2	2.016		15,220.		-		15,214.
OXYGEN	O_2	32.0		-		-		-
NITROGEN & ARGON	N_2	28.016		3,898.		-		3,898.
SULFUR	S	32.06		-		-		-
CHLORINE	Cl	35.453		-		-		-
CARBON MONOXIDE	CO	28.01		440,023.		-		439,242.
CARBON DIOXIDE	CO_2	44.01		38,403.		-		20,632.
METHANE	CH_4	16.042		36,738.		-		36,738.
ETHYLENE	C_2H_4	28.052		1,904.		-		1,904.
ETHANE	C_2H_6	30.068		3,005.		-		3,005.
PROPYLENE	C_3H_6	42.078		-		-		-
PROPANE	C_3H_8	44.094		-		-		-
HYDROGEN SULFIDE	H_2S	34.076		15,377.		-		70.
CARBONYL SULFIDE	COS	60.075		943.		-		193.
CARBON DISULFIDE	CS_2	76.13		-		-		-
SULFUR DIOXIDE	SO_2	64.06		-		-		-
NITROUS OXIDE	NO	30.008		-		-		-
AMMONIA	NH_3	17.031		-		5,604.		-
HYDROGEN CYANIDE	HCN	27.026		-		-		-
HYDROGEN CHLORIDE	HCl	36.461		-		-		-
NAPHTHA	-			-		4,028.		-
TAR & OIL	-			-		-		-
ASH	-			-		-		-
OTHER SOLIDS				-		-		-
SUBTOTAL, DRY				555,511.		9,632.		520,896.
WATER	H_2O	18.016		1,050.		145,902.		25.
TOTAL, WET				556,561.		155,534.		521,153.
GAS MOLECULAR WEIGHT			20.42			-	19.81	
TEMPERATURE, °F			100.			-	57	
PRESSURE, PSIA			430.			-	425.	
SCFH			10,342,893.			-	9,985,973.	
GPM			-			-	-	

TABLE 5.2 (Continued)

MATERIAL BALANCE
LURGI/BGC PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			4-2		8-1		7-1	
STREAM ID			AGR OFF-GAS TO SULFUR RECOVERY		SOLIDS TO FINAL DISPOSAL		WET HHG PRODUCT GAS	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01		-		1,212.		-
HYDROGEN	H_2	2.016		6.		-		15,183.
OXYGEN	O_2	32.0		-		-		-
NITROGEN & ARGON	N_2	28.016		-		-		3,889.
SULFUR	S	32.06		-		-		-
CHLORINE	Cl	35.453		-		-		-
CARBON MONOXIDE	CO	28.01		782.		-		-
CARBON DIOXIDE	CO_2	44.01		17,771.		-		-
METHANE	CH_4	16.042		-		-		-
ETHYLENE	C_2H_4	28.052		-		-		-
ETHANE	C_2H_6	30.068		-		-		-
PROPYLENE	C_3H_6	42.078		-		-		-
PROPANE	C_3H_8	44.094		-		-		-
HYDROGEN SULFIDE	H_2S	34.076		15,307.		-		-
CARBONYL SULFIDE	COS	60.075		750.		-		-
CARBON DISULFIDE	CS_2	76.13		-		-		-
SULFUR DIOXIDE	SO_2	64.06		-		-		-
NITROUS OXIDE	NO	30.008		-		-		-
AMMONIA	NH_3	17.031		-		-		-
HYDROGEN CYANIDE	HCN	27.026		-		-		-
HYDROGEN CHLORIDE	HCl	36.461		-		-		-
NAPHTHA	-			-		-		-
TAR & OIL	-			-		-		-
ASH	-			-		59,650.		-
OTHER SOLIDS				-		30.		-
SUBTOTAL, DRY				34,616.		60,897.		519,853.
WATER	H_2O	18.016		1,230.		6,766.		70.
TOTAL, WET				35,846.		67,663.		519,923.
GAS MOLECULAR WEIGHT			37.15			-		19.81
TEMPERATURE, °F			120.			-		120. (MAX.)
PRESSURE, PSIA			24.			-		615. (MIN.)
SCFH			366,142.			-		9,962,103.
GPM			-			-		-

TABLE 5.2 (Continued)

MATERIAL BALANCE
LURGI/BGC PROCESS
INTEGRATED FACILITY/MODULE DEFINITION

STREAM NUMBER			6-1		5-1		13-1	
STREAM ID			OXIDANT TO GASIFIER		TAIL GAS FROM SULFUR RECOVERY		BY-PRODUCT SULFUR	
	SYMBOL	FORMULA WEIGHT	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR	LB-MOLS/HR	LBS/HR
CARBON	C	12.01		-		-		-
HYDROGEN	H_2	2.016		-		-		-
OXYGEN	O_2	32.0		169,519.		-		-
NITROGEN & ARGON	N_2	28.016		3,029.		28,405.		-
SULFUR	S	32.06		-		-		14,887.
CHLORINE	Cl	35.453		-		-		-
CARBON MONOXIDE	CO	28.01		-		-		-
CARBON DIOXIDE	CO_2	44.01		-		20,015.		-
METHANE	CH_4	16.042		-		-		-
ETHYLENE	C_2H_4	28.052		-		-		-
ETHANE	C_2H_6	30.068		-		-		-
PROPYLENE	C_3H_6	42.078		-		-		-
PROPANE	C_3H_8	44.094		-		-		-
HYDROGEN SULFIDE	H_2S	34.076		-		0.05		-
CARBONYL SULFIDE	COS	60.075		-		-		-
CARBON DISULFIDE	CS_2	76.13		-		-		-
SULFUR DIOXIDE	SO_2	64.06		-		-		-
NITROUS OXIDE	NO	30.008		-		-		-
AMMONIA	NH_3	17.031		-		-		-
HYDROGEN CYANIDE	HCN	27.026		-		-		-
HYDROGEN CHLORIDE	HCl	36.461		-		-		-
NAPHTHA	-			-		-		-
TAR & OIL	-			-		-		-
ASH	-			-		-		-
OTHER SOLIDS				-		-		-
SUBTOTAL, DRY				172,548.		48,421.		14,887.
WATER	H_2O	18.016		-		1,830.		-
TOTAL, WET				172,548.		50,251.		-
GAS MOLECULAR WEIGHT			31.92		32.02			-
TEMPERATURE, °F			302.		100.			-
PRESSURE, PSIA			505.		14.7			-
SCFH			2,051,425.		595,5[illegible]			-
GPM			-		-			-

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TABLE 5.3
ENERGY BALANCE, 10^6 BTU PER HOUR
LURGI BGC MODULE
INTEGRATED FACILITY/MODULE DEFINITION

ENTHALPY BALANCE	PHASE	HHV	LATENT	SENSIBLE	TOTAL
INLETS					
STREAM Coal	Solid	4861	-	-	4861.0
Air to Air Sep'n	Gas	-	7.2	-	7.2
Raw Water	Liquid	-	-	-	
SUBTOTAL IN					4868.2
OUTLETS					
STREAM MBG	Gas	3817	-	-	3817.0
Ash	Solid	-	-	-	0
Tail Gas	Gas	-	2.1	0.2	2.3
Sulfur	Solid	59.4	-	0.5	59.9
Air Sep'n Vent	Gas	-	6.7	3.8	10.5
Flue Gases	Gas	-	62.0	62.3	124.3
Ammonia	Gas	4.0	-	-	54.0
Wastewater	Liquid		-	16.0	16.0
SUBTOTAL OUT					4084.0
NET INLET-OUTLET					784.2
HEAT AND SHAFT WORK					131.3
ELECTRIC POWER			-		0
SHAFT WORK			395.8	-395.0	-790.8
HEAT REJECTION					0
HEAT INPUT (STEAM)					-25
RADIATION/FUGITIVE LOSS					-684.5
SUBTOTAL NET VALUE					684.5
TOTAL ABSOLUTE VALUE					

BALANCE: $\frac{\text{NET ENTHALPHY + NET HEAT \& SHAFT WORK}}{\text{TOTAL ABSOLUTE VALUE OF HEAT \& SHAFT WORK}} = \frac{784.2 - 684.5}{684.5} \times 100 = 14.5$

BASIS: 60°F, LIQUID WATER

TABLE 5.4
CONVERSION EFFICIENCY
BGC/SLAGGING LURGI PROCESS
20,000 TPD FACILITY

	10^6 BTU/HR	PERCENT
INPUTS		
1. COAL TO FACILITY	27,852	
2. ELECTRIC POWER TO FACILITY	525	
OUTPUTS		
3. MBG FROM FACILITY	15,268	
4. COAL FINES FROM FACILITY	8,404	
EFFICIENCY		
COAL-TO-MBG (3 ÷ 1) x 100%		54.8%
OVERALL PRODUCT EFFICIENCY 3 ÷ (1 + 2) x 100%		53.8%
OVERALL FACILITY EFFICIENCY 3 + 4 ÷ (1 + 2) x 100%		83.4%
GASIFICATION EFFICIENCY 3 ÷ (1 + 2 - 4) x 100%		76.4%

TABLE 5.5. OPERATING REQUIREMENTS FOR EXPECTED OPERATIONS
LURGI/BGC PROCESS - PER MODULE

	BASIS	UNITS
Raw Materials		
Coal Import	TPY at 100% Operation	2,777,650 TPY
Coal Fines Export	TPY at 100% Operation	589,167 TPY
Catalyst and Chemical Makeup	100% Operation	1,204,500/YR
Utility Requirements		
Import Power	kWh/HR at 100% Operation	259,558,800 kWh/YR
Operating Requirements		
Labor		
Supervisors	Man-Hours/YR	30,000 mh/YR
Operators	Man-Hours/YR	145,720 mh/YR
Supplies	Factored as 15% of Operating Labor Cost	
Maintenance Requirements		
Labor	Factored at 1.6% of Total Depreciable Direct Investment	
Supplies	Factored at 2.4% of Total Depreciable Direct Investment	

6.0 DESIGN INFORMATION SOURCES

(1) Economic Studies of Coal Gasification Combined Cycle Systems for Electric Power Generation, (January, 1978), EPRI Report AF-642.

(2) Effects of Sulfur Emission Controls on the Cost of Gasification Combined Cycle Power Systems, (October, 1978), EPRI Report AF-916.

(3) Evaluation of Intermediate-Btu Coal Gasification Systems for Retrofitting Power Plants, (August, 1977), EPRI Report AF-531.

(4) Economics of Current and Advanced Gasification Processes for Fuel Gas Production, (July, 1976), EPRI Report AF-244.

APPENDIX B-5

COAL GASIFICATION FACILITY
SCHEDULE ANALYSIS

TABLE OF CONTENTS

LIST OF TABLES

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LIST OF FIGURES

PROJECT SCHEDULES

This appendix contains the master and project schedules needed to support the evaluation of the reference facility designs, economic studies and project planning for the TVA coal gasification facility. Enclosed are five such schedules: one Coal Gasification Facility Project - Master Schedule and four project schedules for each of the four TVA Medium-Btu Gasification (MBG) Modules. The schedules are time-phased by project activity (such as engineering, procurement, construction and testing) and by module or by the major systems (such as air separation, gasification, etc.). These schedules developed at this early stage of the project should be considered as anticipatory rather than definitive and should be useful for overall project comprehension.

1.0 LEVELS OF SCHEDULES

There are three distinct types of schedules differing in the level of detail they provide. These schedules are:

1.1 Management Schedules

Management level schedules identify the basic milestones and parameters of a project. These schedules are normally originated during the planning and preliminary engineering phase of a project. The types of management schedules and a brief description of their use are as follows:

- Proposal Schedule - Assists business development in its efforts to gain new contracts.
- Front End Schedule - Depicts the key activities to be accomplished during the first sixty to ninety days after project award in order to successfully start the project.
- Master Schedule - Defines major milestone events for engineering, procurement and construction, and provides the basic parameters for more detailed project and control level schedules.

1.2 Project Schedules

Project schedules provide a greater quantity of detail. They are designed for the use of those directly involved on a day-to-day basis in the management of the gasification project.

Project schedules depict the project plan and are developed after management level schedules have been approved and issued. The types of project schedules and a brief description of their use are as follows:

- Engineering Network - A critical path method diagram which details the activities and targets of engineering and procurement as established by the master schedule.

- Engineering Schedule - A bar chart time-scaled format which details the activities and targets of engineering and procurement as established by the master schedule.
- Construction Network - A critical path method diagram which details the activities and targets of construction as established by the master schedule.
- Construction Schedule - A bar chart time-scaled format which details the activities and targets of construction as established by the master schedule.

1.3 Control Schedules

Control schedules provide the greatest amount of detail. Such schedules, when integrated with control reports, provide the detailed information necessary to effectively and accurately evaluate project performance. Control level schedules and reports should be maintained and updated by the person responsible for the work, in conjunction with the schedule engineer. Control level schedules and reports are the basis for project and management level schedules and reports. Control level schedules and reports are divided into three basic types: engineering, procurement, and construction. Each type of control schedule relates directly to a particular phase of the project.

2.0 CONTENT OF REPORT

This report first presents a "Coal Gasification Facility Project - Master Schedule." The master schedule is a management level schedule and depicts only major milestone events and major phases of the project such as engineering, procurement, and construction. It provides module rather than system level of detail. The purpose of the master schedule is to depict in the most general terms the overall plan for the execution of the project with regard to time and resources. The master schedule serves as a basis for the preparation of more detailed schedules and logic networks. It is important that the master schedule be agreed upon and fixed as early in the project as possible since so much of the other planning and scheduling relies upon it. It is not intended to be revised. Only major changes in scope of work or major interruptions due to factors such as labor strikes should justify revision of the master schedule.

Four project schedules are presented to accompany the master schedule. Each one depicts the time-phasing for the development of a particular module at the system level of detail. Utilizing a bar chart time-scaled format, they detail major milestones for engineering, procurement, construction, and testing.

Control schedules by their nature are too detailed for inclusion in this report. For examples of their proper use refer to: K. M. Guthrie, Managing Capital Expenditure for Construction Projects, Craftsman Book Company of America, Solana Beach, California (1977).

All schedules contained in this report have been made consistent with the Coal Gasification Facility Work Breakdown Structure Matrix as given in Appendix H.

It is recognized that the final allocation of systems within this Work Breakdown Structure may be changed in the future. For example, the category of Off Sites Systems may cease to exist, and the systems assigned to it (e.g., Coal Handling, Solids, Disposal, etc.) may be reallocated to a different category. The section which follows will describe the methodology used in preparing the schedules described above.

3.0 METHODOLOGY

The following material in this chapter outlines the four basic steps necessary in the development of a master schedule and the required project schedules. These four steps are:

- Collection of Information
- Determination of Controlling Factors
- Schedule Preparation and Analysis
- Review and Issue

3.1 Collection of Information

This initial step is the most critical since all assumptions, suppositions, and determinations are made from the data collected. The information was divided into major categories as follows:

3.1.1 Project Information

The master schedule as conceived by the Tennessee Valley Authority (TVA) gasification project team and the NASA gasification project team was used as a starting point for the schedule development. All milestones and essential schedule project schedule dates were used as the basis for schedule development.

3.1.2 Engineering, Procurement, and Construction Information

Information was collected by system type for engineering, procurement, and construction. Engineering was assumed to include activities occuring between initiation of home office engineering and design to approval for construction process implementation. Procurement was assumed to begin with the initiation of bid requests to hardware suppliers to the actual delivery of the systems on site. Construction was assumed to begin with manufacture of the field unit and implementation on site to the activities which commenced systems test. The TVA/NASA best estimates for each segment of engineering, procurement, and construction were extracted from the master schedule and compared with the best estimates made by personnel on the BDM/Mittelhauser project team. The results of both estimates have been used to develop the project schedule enclosed.

In most cases, the BDM/Mittelhauser team's estimates were more conservative than the original TVA/NASA estimate. In any case, the least conservative estimate became the low estimate (indicated by the solid line on the project schedules) and the more conservative estimate became the high estimate (indicated by the broken line extension of the project schedule). All timelines were presented as typical for construction projects of this type and do not represent a detailed risk analysis of this project.

3.1.3 Systems and Module Test and Evaluation Information

The start-up and test cycle as defined by TVA was divided into two segments: (1) Systems Test and Evaluation set at sixteen (16) months during which time each system as it is implemented is tested independently of all other systems in the module, and (2) Module Test and Evaluation set at six (6) months during which time all systems are integrated and tested as a complete module. In all cases, systems test and evaluation overlap the construction activities and the module test and evaluation commences with completion of systems test and evaluation and ends with the start of commercial operations.

3.1.4 Cost Engineering Information

The schedule development was made to be consistent with the Work Breakdown Structure as defined in the April 30 interim report. It is recognized that the subsequent development of reference designs and cost estimations might cause a reallocation of systems within the structure. At a future date, the schedules should be made consistent with any changes made to the Work Breakdown Structure which result from experience in the cost estimation and engineering design process.

3.2 Determination of Controlling Factors

The TVA Coal Gasification Facility proposed schedule as defined in Table 4.1 is the primary controlling factor for all major milestones established in the master schedule. The proposed schedule provides all the major milestone events necessary to effectively outline the execution and completion of the project and to commence commercial operation of the modules 1-4 in years 1985-87. The determination of major equipment deliveries is the prime controlling factor in establishing whether such a schedule can be met. Best estimates by TVA/NASA and BDM/Mittelhauser indicate that such a schedule is achievable, but much depends on the future procurement schedules agreed to by the hardware suppliers. No attempt has been made in this study effort to identify and contact the hardware vendors to estimate future procurement schedules for each system.

3.3 Schedule Preparation and Analysis

The information obtained in the data collection process was organized by system (e.g., gasification, process solids, etc.) and by activity (engineering, procurement, and construction). For each system, the best estimates of time requirements for the activities of engineering, procurement and construction were analyzed to determine the values to be scheduled. For example, the time estimates for TVA/NASA and BDM/Mittelhauser are given for the activities of engineering, procurement, and construction as well as the estimations for time overlap between engineering procurement and procurement-construction. In the example, the BDM/Mittelhauser estimates for engineering and procurement were lower than the TVA/NASA estimates and therefore used as the resultant low estimates for those same activities. The TVA/NASA estimate for construction was lower than the BDM/Mittelhauser estimate and therefore used as the low estimate for construction. In all cases, the overlap estimates have been used as flexible categories to assure that the combined totals can be satisfied within the project major milestones.

After completing the above process for each system, the combined totals were assigned short, medium, or long time requirement ranges according to the following definitions:

$$\begin{array}{lll} & \text{long time} & \geq 40 \text{ months} \\ 34 \text{ months} \leq & \text{medium time} & < 40 \text{ months} \\ & \text{short time} & < 34 \text{ months} \end{array}$$

For example, the gasification system combined total is 46-51 months to engineer, procure and construct the system, and is a system having by definition, a long time requirement. All systems with similar long time requirements were scheduled first; systems with medium time requirements were scheduled second; and finally the systems with the short time requirements, and therefore the greatest flexibility, were scheduled last.

The resultant schedules are shown in Section 4.0.

3.4 Review and Issue

The submission of this document to TVA and NASA commences the final step in the schedule development. The schedule may be finalized and approved by TVA and NASA or revised as necessary to permit latest changes in plans by those organizations. In any case, project and control schedules must be developed in greater detail to permit careful monitoring of the gasification project.

4.0 REFERENCE FACILITY SCHEDULES

4.1 Milestones

The program development methodology encompasses the establishment of a specific set of time-structured elements scheduled for completion at pre-designated dates. To facilitate effective program management of system development, and to ensure management review of program status, a set of objective-oriented milestones has been established. These milestones include:

- Program Requirements Review (PRR)
- Preliminary Design Review (PDR)
- Critical Design Review (CDR)
- Operational Readiness Review (ORR)
- Start of Commercial Operations (SCO)

4.1.1 Program Requirements Review (PRR)

The PRR will be a vehicle for review and approval of the complete systems requirements for all functions to be performed by the coal gasification facility. It will occur four months from the start date and will present for program management approval a complete Functional Description, a Test Plan and a list of system deliverables related to both the total systems and individual module development.

4.1.2 Preliminary Design Review (PDR)

The PDR will occur twelve months after the start date and at this time program management will review the complete system and subsystem designs. All system and subsystem specifications will be completed in draft form for review. The Test Requirements will be approved at this review. Construction of well defined systems such as coal handling, solids disposal, plant power, general facilities may begin shortly after the PDR and prior to the critical design review.

4.1.3 Critical Design Review (CDR)

Twenty months from the start date, a CDR will be held to approve all specifications. The drafts presented at the PDR will be revised as necessary to meet program development requirements, and specifications will be defined to the subsystem level. The final version of system, subsystem, and test specifications will be approved at the CDR. Approval of the CDR will mark the initiation of major construction activity for all systems not already started. The final designs and specifications provide the necessary guidance and instructions for remaining program development activities.

4.1.4 Operational Readiness Review (ORR)

This milestone is the fourth to be reached and occurs approximately 51 months from the program start date. The objective of the ORR is to review completed system acceptance test results to determine operational readiness of each module. Complete program documentation review is also performed during this review. Following the ORR, a six-month period of module testing will commence.

4.1.5 Start of Commercial Operation (SCO)

The SCO constitutes the final phase of program development. The results of module testing and evaluation will be reviewed and commercial operation of each module will commence. Total facility management, operation, maintenance, and logistic support will proceed in accordance with the conceptualized standard operating procedures, facility operating instruction, system safety plans, and quality assurance requirements.

4.2 Schedule Dates

Table 4.1 provides schedule dates encompassing the complete life cycle of the MBG facility. The phases for module development and operation include:

- Design and Construction
- Start-up/Test (System and Module)
- Start Commercial Operation
- Module Retirement

4.3 Master Schedule

The major program development activities and their time-phased relationship to each of the four system modules is shown in the Coal Gasification Facility Project Master Schedule (Figure 4.1). Specific major activities include engineering procurement, construction, and testing. Also included are the program milestones and their associated dates.

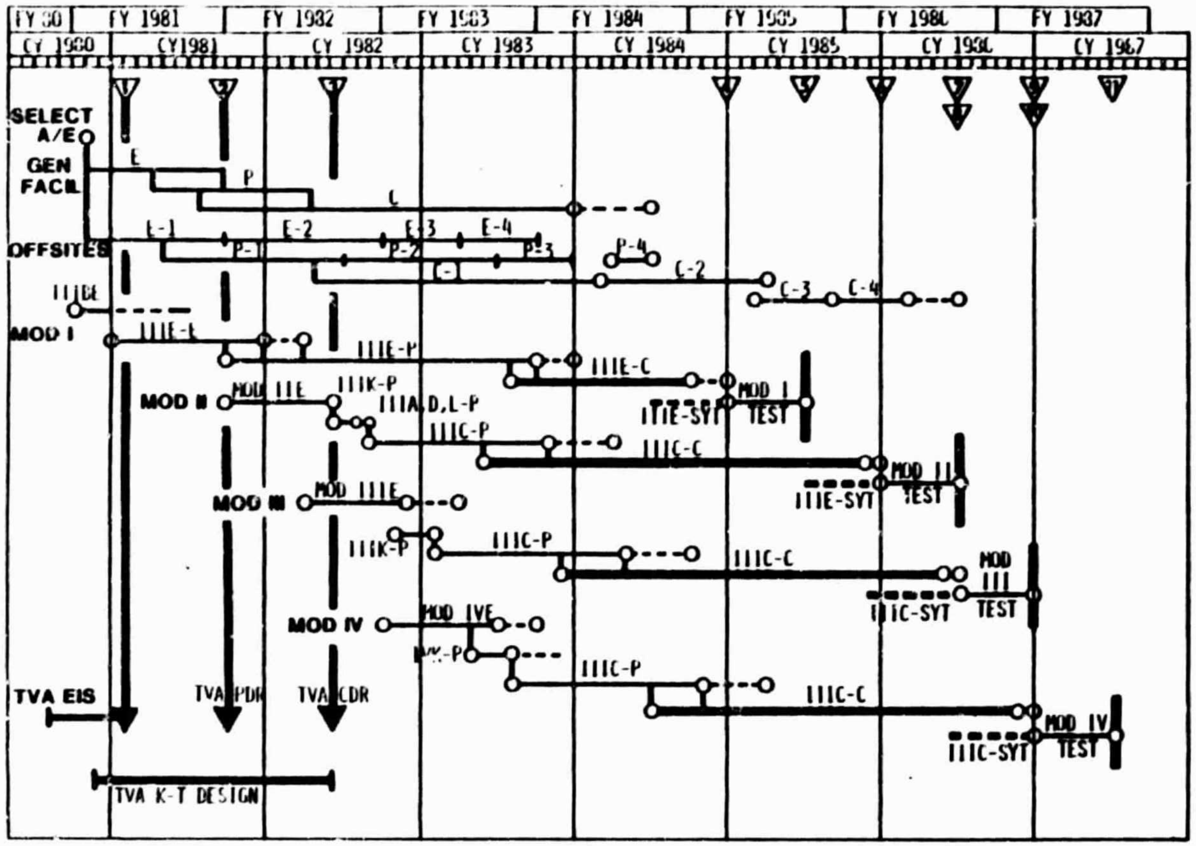
4.4 Project Schedules

Figures 4.2 to 4.5 depict major systems development activities and milestones defined in Section 4.1 for each individual coal gasification module to be developed. Both low and high time estimates of each major development activity have been established according to the methodology defined in Section 4.3.

TABLE 4.1. THE TVA COAL GASIFICATION FACILITY PROPOSED SCHEDULE

	MODULE I	MODULE II	MODULE III	MODULE IV
DESIGN AND CONSTRUCT				
BEGIN	10-01-80	10-01-81	4-01-82	10-01-82
COMPLETE	12-31-84	12-31-85	6-30-86	12-31-86
START-UP/TEST				
SYSTEM TEST - BEGIN	9-01-83	9-01-84	3-01-85	9-01-85
- COMPLETE	12-31-84	12-31-85	6-30-86	12-31-86
MODULE TEST - BEGIN	1-01-85	1-01-86	7-01-86	1-01-87
- COMPLETE	6-30-85	6-30-86	12-31-86	6-30-87
START COMMERCIAL OPN.	7-01-85	7-01-86	1-01-87	7-01-87
RETIRE MODULE	6-30-05	6-30-06	12-31-06	6-30-07

TVA SCHEDULING FOR MBG PLANT SUMMARY DIAGRAM



PROJECT SCHEDULE MILESTONES

1. PROGRAM REQUIREMENTS REVIEW 2-1-81
2. PRELIMINARY DESIGN REVIEW 10-1-31
3. CRITICAL DESIGN REVIEW 6-1-82
4. OPERATIONAL READINESS REVIEW- MOD I
5. START COMMERCIAL OPERATION, MOD I
6. ORR - MOD II 12-31-85
7. SCO - MOD II 6-30-86
8. ORR - MOD III 6-30-86
9. SCO - MOD III 12-31-86
10. ORR - MOD IV 12-31-86
11. SCO - MOD IV 6-30-87

NOTES FOR MODS

III - PROCESS FACILTIIES
IIIB - GASIFICATION SYSTEM
IIIC - INITAIL GAS CLEAN/COOL SYSTEM
IIIE - GAS COMPRESSION SYSTEM
E - ENGINEER
P - PROCURE
C - CONSTRUCT

CRITICAL ITEMS ONLY:

SEE MODULE SHEETS FOR ENTIRE LISTING, INCLUDING COMMENTS. TWO INHERENT THINGS TO WATCH FOR:

(1) INSURE THAT ALL POSSIBLE EARLY CONSTRUCTION IS COMPLETED BEFORE LAST EQUIPMENT ARRIVES, I.E., MAINTAIN OVERLAP.

(2) ITEMS B (GASIFICATION), C (GAS CLEANUP), D (ACID GAS REMOVAL) ARE TIME-CONSUMING TO TEST, WILL REQUIRE RELATIVELY LONG TIME BEFORE ATTAINING DESIGN-SCALE EQUILIBRIUM.

Figure 4.1. Master Schedule

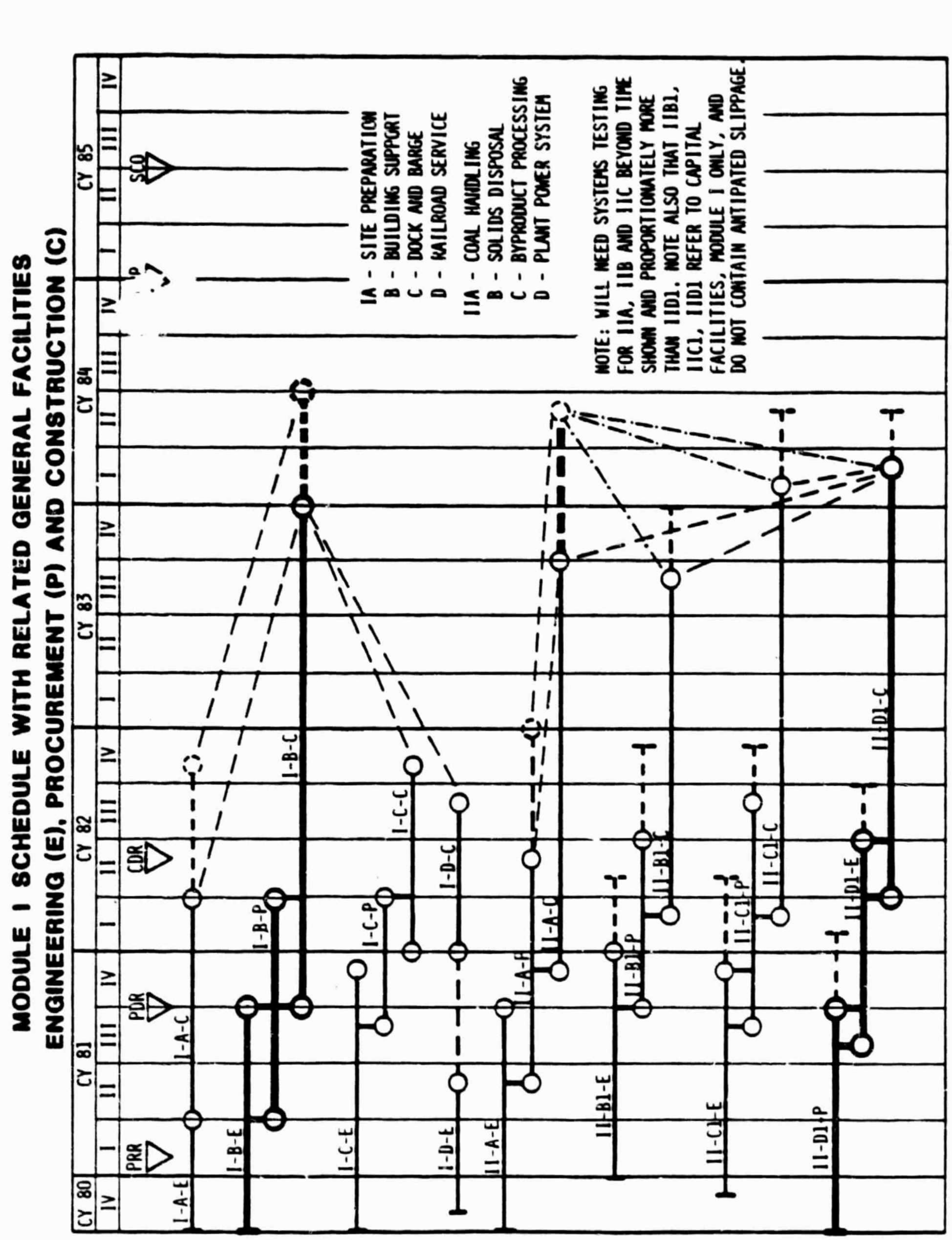


Figure 4.2 (a). General Facilities Schedule

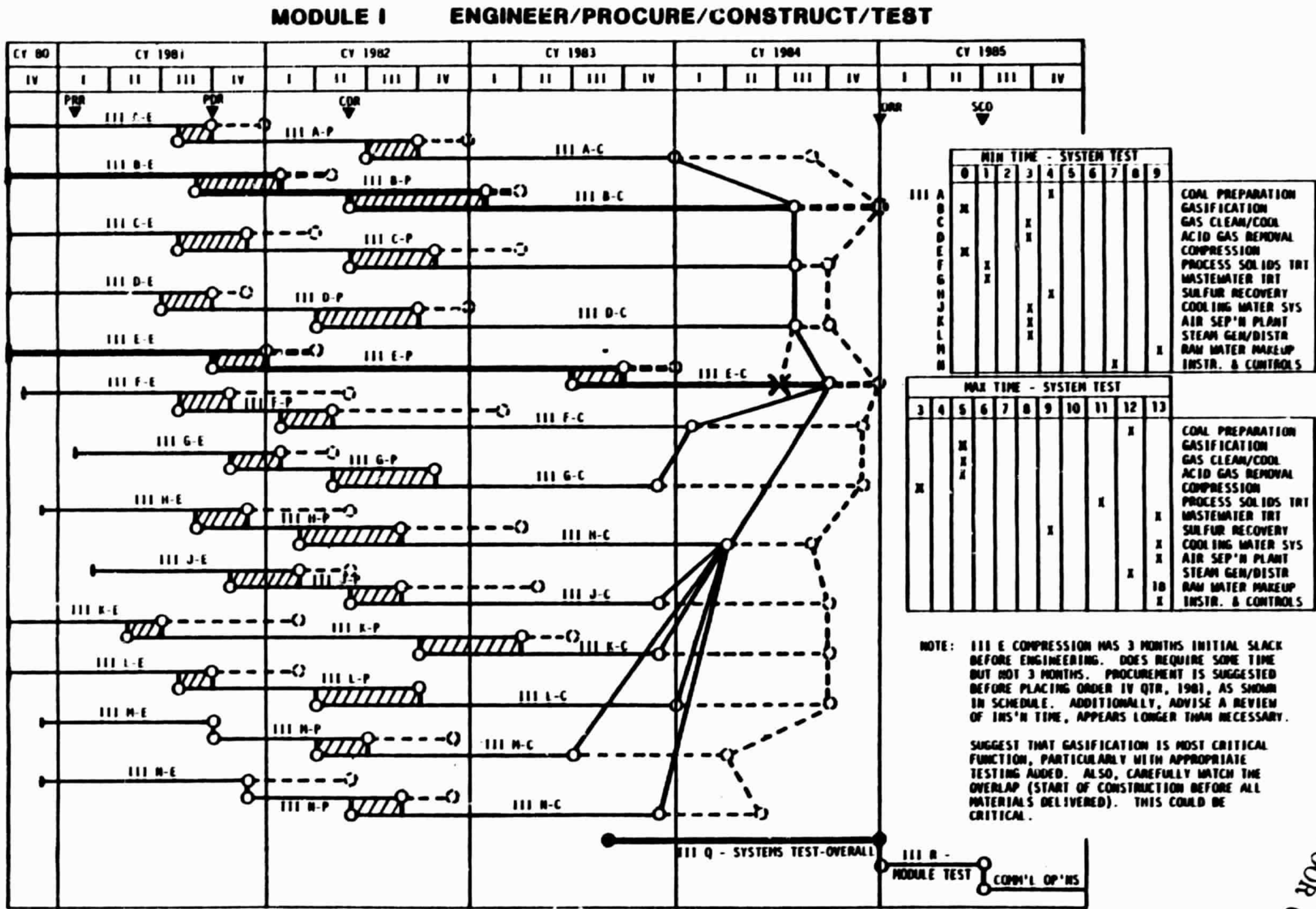
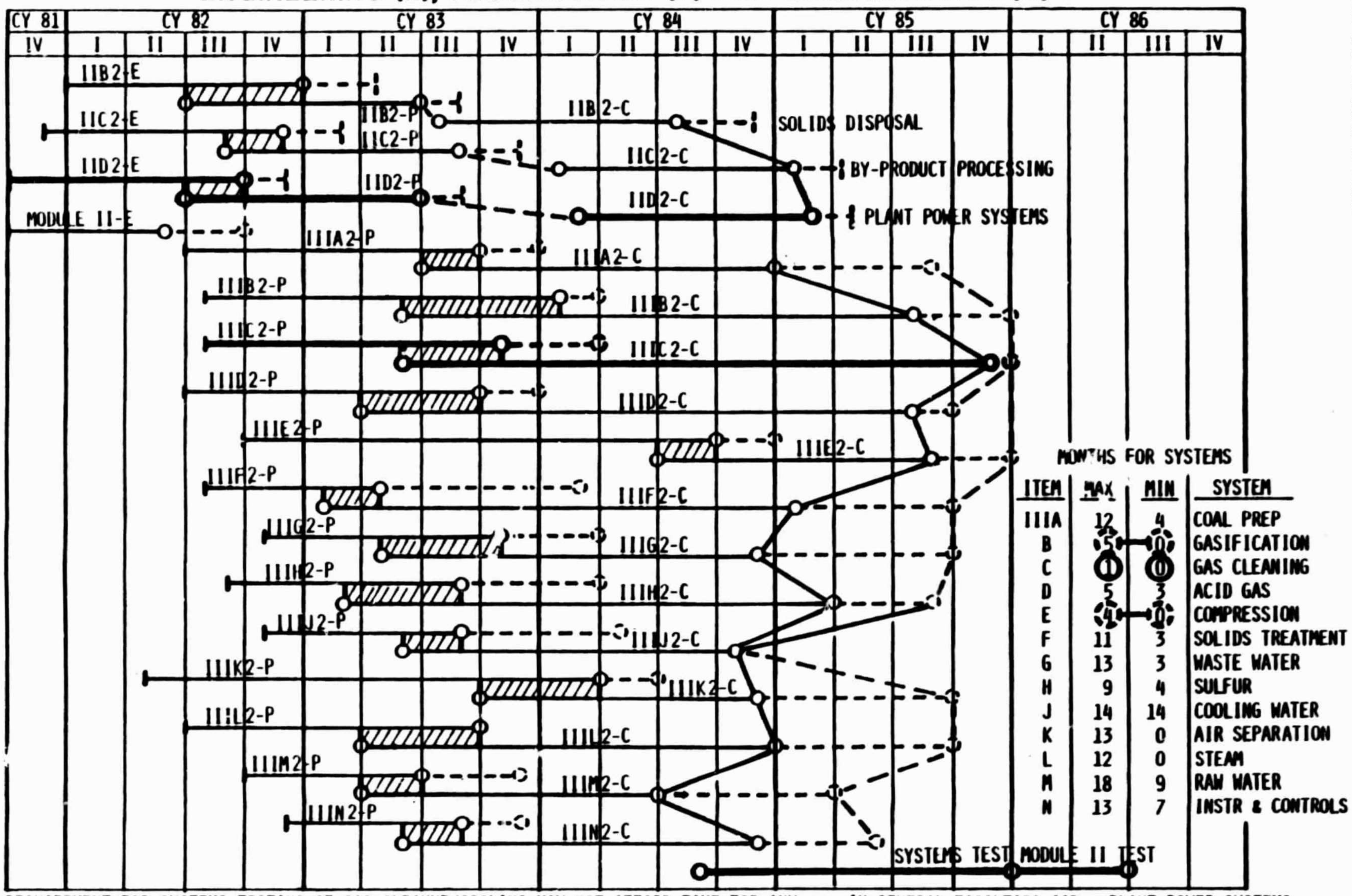


Figure 4.2 (b). Module I Schedule

ORIGINAL PAGE IS OF POOR QUALITY

MODULE II SCHEDULE WITH RELATED GENERAL FACILITIES ENGINEERING (E), PROCUREMENT (P) AND CONSTRUCTION (C)

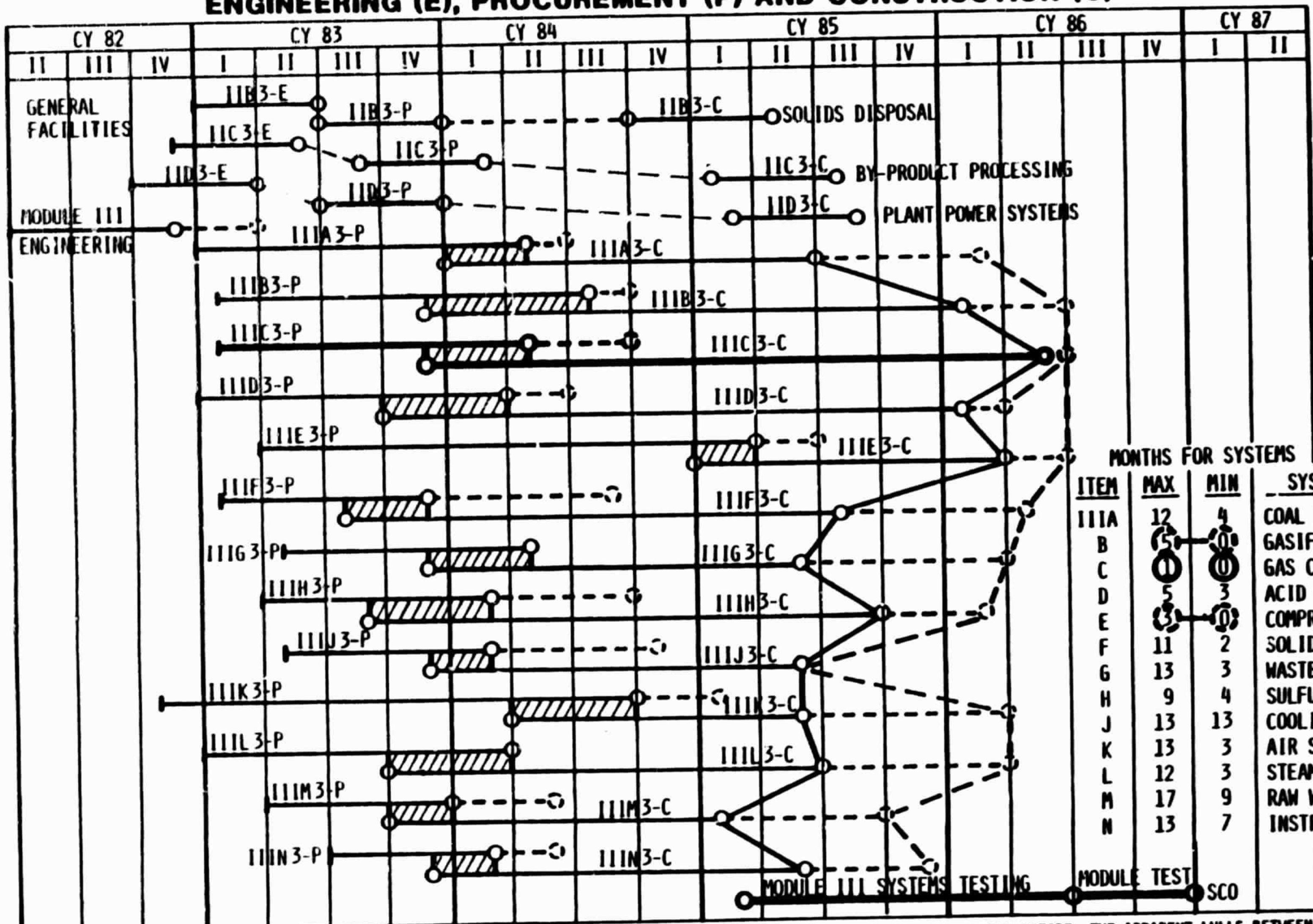


NOTE: REQUIREMENT FOR SYSTEMS TESTING OF GAS CLEANUP/COOLING MAY NOT AFFORD TIME FOR ANY SLIPPAGE OR FOR ADEQUATE TESTING. HOWEVER, PROCUREMENT AND CONSTRUCTION MAY BE INITIATED EARLIER IN PLANNED CONSTRUCTION PERIOD OF MODULE II PROCESSING FACILITIES

IN GENERAL FACILTIES IID-- PLANT POWER SYSTEMS - 8 MONTH HIATUS BETWEEN PURCHASE COMPLETION AND CONSTRUCTION START DOES NOT APPEAR NECESSARY.

Figure 4.3. Module II Schedule

MODULE III SCHEDULE WITH RELATED GENERAL FACILITIES ENGINEERING (E), PROCUREMENT (P) AND CONSTRUCTION (C)

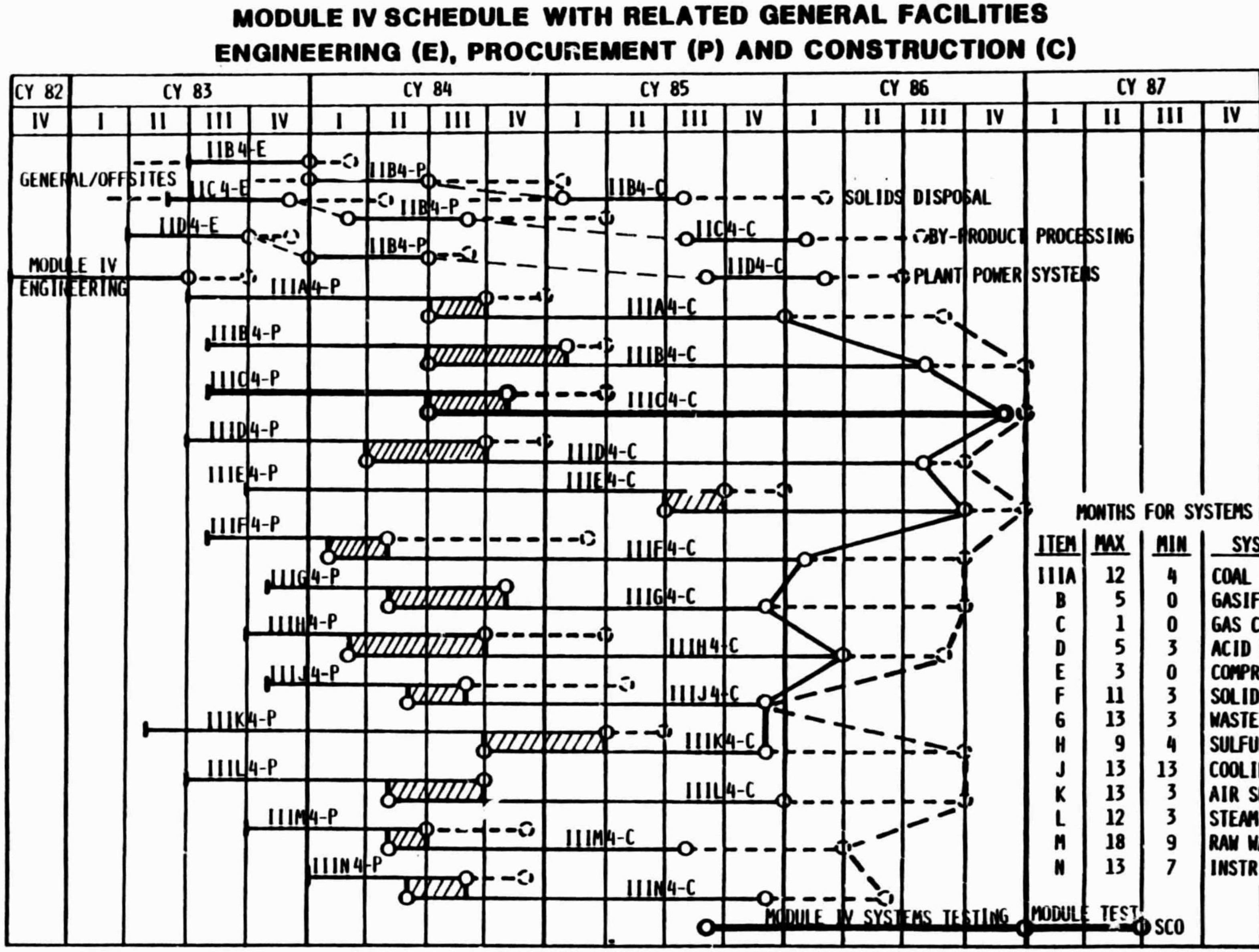


ITEM	MAX	MIN	SYSTEM
IIIA	12	4	COAL PREP
B	5	0	GASIFICATION
C	0	0	GAS CLEANING
D	5	3	ACID GAS
E	3	0	COMPRESSION
F	11	2	SOLIDS TREATMENT
G	13	3	WASTE WATER
H	9	4	SULFUR
J	13	13	COOLING WATER
K	13	3	AIR SEPARATION
L	12	3	STEAM
M	17	9	RAW WATER
N	13	7	INSTR & CONTROLS

AS NOTED IN MODULES I AND II, THE BASE DETERMINANT OF TIMELY PLANT OPERATIONS WILL BE SUFFICIENT TIME AVAILABLE FOR TESTING, EVALUATING AND DEBUGGING PROCESS FACILITIES. INITIAL GAS CLEANUP AND COOLING STILL APPEARS TO BE MOST SENSITIVE FUNCTIONAL AREA WITH COMPRESSION AND GASIFICATION NEXT MOST CRITICAL. IT IS BELIEVED THAT INSTALLATION TIME SHOWN FOR COMPRESSION IS MORE THAN ADEQUATE WITH APPROPRIATE SCHEDULING, TO RECEIVE, INSTALL, CONNECT, TEST AND INTEGRATE INTO MODULE PROCESS FLOW.

ALSO AS NOTED BEFORE, THE APPARENT LULLS BETWEEN ENGINEERING, PROCUREMENT AND CONSTRUCTION FOR THE RELATED GENERAL FACILITIES DOES NOT APPEAR REALISTIC, HOWEVER, IT DOES RAISE A QUESTION ABOUT FRONT-LOADING THESE ACTIVITIES TO SAVE CONSTRUCITON TIME AND INFLATIONARY ESCALATIONS.

Figure 4.4. Module III Schedule



ITEM	MAX	MIN	SYSTEM
IIIA	12	4	COAL PREP
B	5	0	GASIFICATION
C	1	0	GAS CLEANING
D	5	3	ACID GAS
E	3	0	COMPRESSION
F	11	3	SOLIDS TRTMNT
G	13	3	WASTE WATER
H	9	4	SULFUR
J	13	13	COOLING WATER
K	13	3	AIR SEPAR'N
L	12	3	STEAM
M	18	9	RAW WATER
N	13	7	INSTR & CONTR

THE SAME ELEMENTS APPLY TO MODULE IV AS FOR PRIOR FACILITIES.

Figure 4.5. Module IV Schedule